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I. INTRODUCTION AND STATEMENT OF WORK

In this report the current assessments of fossil fuel resources in the United States are examined, and predictions of the maximum and minimum lifetimes of recoverable resources according to these assessments are presented. In addition, current rates of production in quads/year for the fossil fuels have been determined from the literature.

Where possible, costs of energy, location of reserves, and remaining time before these reserves are exhausted are given. In addition, limitations that appear to hinder complete development of each energy source are outlined.

Using the data on maximum and minimum recoverable reserves and current use rates, predictions of lifetimes of remaining recoverable reserves are determined as follows: A rate of increase, b, is assumed to occur each year over the current production rate. At time t in the future, the production rate P(t) will have increased over the current production rate, $P(t = 0)$ by the relation

$$P(t) = P(t=0)e^{bt} \tag{1}$$

The cumulative production C from the present to time t is given by

$$C = \int_{\tau=0}^{t} P(\tau)d\tau = \int_{\tau=0}^{t} P(\tau=0)e^{b\tau}d\tau = \frac{P(t=0)}{b}(e^{bt} - 1) \tag{2}$$

At some time t, the cumulative production C from the present becomes equal to the remaining recoverable reserves, R. This is the time of predicted depletion given by rearranging equation 2 to give

$$t = \frac{1}{b}\ln\left[\frac{bR}{P(t=0)} + 1\right] \tag{3}$$

For the case of $b = 0$ (present use rate), this reduces to

$$t = \frac{R}{P(t=0)} \tag{4}$$

This approach assumes that an increase in use rate, b, remains constant over the lifetime of reserves, and that production keeps pace with demand. Actually, neither of these assumptions is likely, and shortages will occur well before predicted depletion times because of limits to production, already evident in US natural gas and petroleum. However, resources themselves will last longer than predicted here because b will be reduced due to production limitations toward the end of the resource production period.

Part II of this report brings together information from a variety of sources to detail the fossil fuel resources of the United States. All data has been put in terms of the values generally used for the particular resource; e.g., barrels for oil, and additionally into units of quadrillion (10^{15}) Btu's, or quads, given the unit symbol Q. The latter units allow comparison of resources among the various energy forms.

In Part III, the relative costs of transport of various energy sources are compared, with special emphasis on the viability of the available methods of transporting hydrogen.

Finally, Part IV gives a look at hydrogen usage in the residential sector relative to other means of providing energy to the home.

References are numbered within each section and are listed at the end of each section. A list of general references to the recent literature is included as Section V.

II. FOSSIL ENERGY RESOURCES

A. DEPLETABLE RESOURCES

Any of the fossil fuels can be used to produce hydrogen. The general reaction series is

A. Gasification and Shift Conversion

$Fuel + H_2O \rightarrow CH_4 + C + CO$ (coal, shale, oil, tar sands)

$C + H_2O \rightarrow CO + H_2$ (coal, shale, oil, tar sands)

$CO + H_2O \rightarrow CO_2 + H_2$ (coal, shale, oil, tar sands)

B. Production of Synthesis Gas and Shift Conversion

$CH_4 + H_2O \rightarrow 3H_2 + CO$ (natural gas or methane from A)

$CO + H_2O \rightarrow H_2 + CO_2$

C. Purification

$CO_2 + CaO \rightarrow CaCO_3$

$H_2S + CaO \rightarrow CaS + H_2O$

The end products of series A and B are always CO_2 and hydrogen. These methods are well developed: The reactions in set A are those used in coal gasification; those in set B are used in the first step of production of ammonia fertilizer from natural gas.

The great drawback of all of these processes is that the primary fuel itself, or the methane made from them, contains more energy than the resulting hydrogen. The liquid and gaseous forms are all probably as useful as and less expensive per Btu than the hydrogen produced from them.

In addition, the CO_2 must be removed from the gas before pipelining or use. Thus, in addition to the purification step for sulfur removal, a large volume of CO_2 must be removed, resulting in huge amounts of commercially almost valueless $CaCO_3$.

1. Coal

a. National Resources

Coal is the most abundant fossil fuel. According to the Project Independence report [1], sufficient proven recoverable coal reserves mineable at current prices (approximately 7000 Q) exist to allow consumption at present rates for over 500 years. However, other assessments of coal reserves are not so optimistic. Based on National Petroleum Council figures, reference 2 estimates the life of underground recoverable reserves of 105 billion tons (2730 Q) at 58 years, based on a five percent growth rate of demand per year. This figure is based on 50% recovery of economically available reserves which exclude lignite and "intermediate" thickness seams of bituminous and subbituminous coal. Such a growth rate seems quite reasonable given the increased need for coal for many energy uses and the policy of conversion to coal from oil and gas where possible. A similar projection for surface coal recoverable reserves of 45 billion tons (1000 Q) estimates a 46 year life.

The U. S. Geological Survey, as reported in [2], projects that there are 3,224 billion tons (83,824 Q) of remaining coal reserves of which 150 billion tons (3,900 Q) are recoverable (based on depth of overburden less than 1000 feet and seam thickness of 28 inches or more). These figures strongly depend on the cost of recovery. They assume 50 percent recovery of underground coal and 90 percent recovery of strip mined coal, and at costs comparable to the present. New mining technology could help the estimate of reserves to increase considerably.

Merklein [3] gives comparable analysis, predicting 220 billion tons (5,720 Q) of recoverable coal. He also notes that a 5 percent growth

rate will yield a 60 year life for coal reserves.

Figure IIA1.1 summarizes the estimates of recoverable coal reserves.

Alternative resource depletion estimates are given for coal for various scenarios in Table IIA1.1 and Figure IIA1.2. They project a slightly more optimistic life expectance for coal reserves. These are based on 1972 production rate of 12.4 Q/yr. as given in Reference 1, and use a minimum resource estimate of 3900 Q (based on USGS surface plus underground recoverable reserve predictions). The upper limit for coal is approximately 7000 Q (based on Project Independence data). This upper limit is somewhat artificial in that it represents reserves minable at current prices. Based on the USGS numbers for total remaining reserves, this upper limit is nearer 80,000 Q.

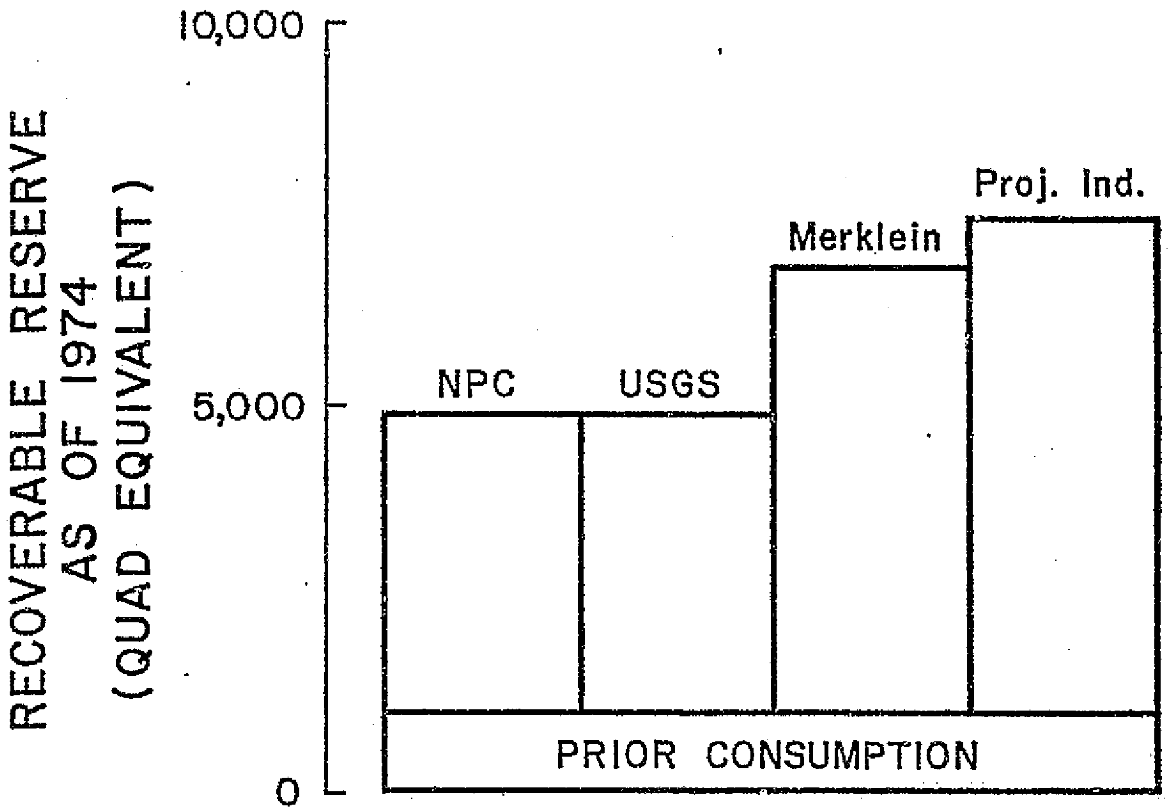

Figure II AI.1

Comparison of Predictions of Recoverable Coal Reserves

Table IIA1.1

Resource Depletion Estimates for Coal for Various Scenarios [4]

	Year in which all Ultimately Recoverable Resources are Depleted			
	Low Estimate		High Estimate	
	EGM[(a)]	RGM[(b)]	EGM	RGM
No Synthetic Fuel	2050+	2050+	2050+	2050+
Synthetic Fuel	2032	2050+	2044	2050+

(a) EGM, extrapolated growth model

(b) RGM, reduced growth model

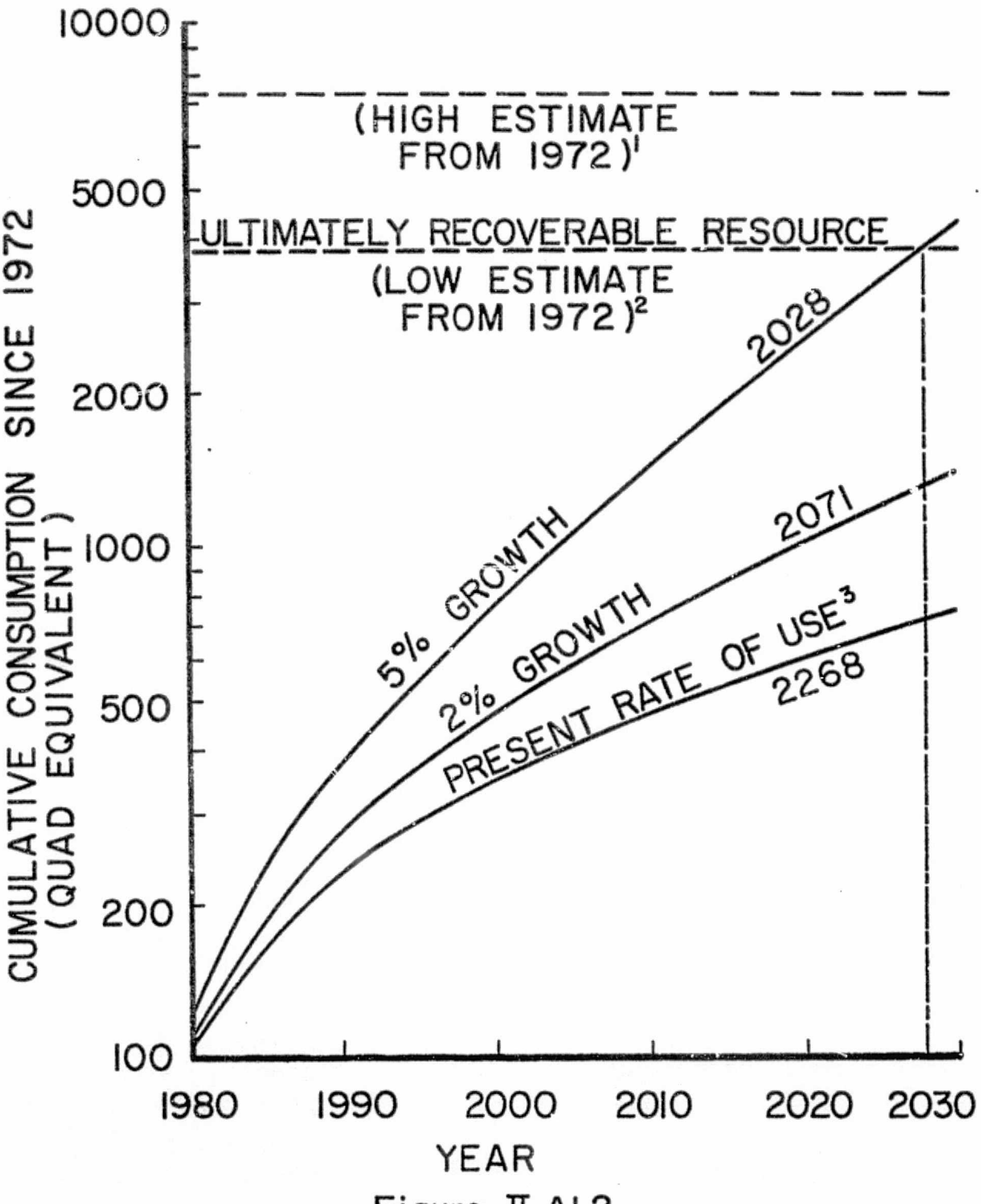

Figure II AI.2

Life Expectance of Coal Reserves

[1] Present prices; total reserves closer to 80,000 Q

[2] Present prices; depth of overburden less than 1000 feet and seam thickness of 28 inches or more

[3] 1972 Production: 12.4 Q/yr

b. Cost

The investment required in an underground coal mining operation is about $18 - $22 to produce one ton per year. For surface mining the cost ranges from $5 - $15 [5, 6].

Table IIA1.2 summarizes the energy content and cost of coal.

Table IIA1.2

Energy Cost for Coal [6]

Coal Type	Energy Content (mm Btu/ton)	Cost $/mm Btu
Surface (Western)	15	0.30
Deep Mined (Northeast)	30	0.70-0.80

Any significant increase in production presumes an associated increase in demand. A significant increase in demand must be the result of the development of new industries for the direct use of coal or for converting it into clean fuels. In any event new transportation and related distribution facilities will about double the cost. Tripling the United States' coal production by 1985 as some have suggested would require an investment totaling $30 billion. This money may be difficult to attract. While the price of coal has increased by 50% since 1970, the coal company's pre-tax profit margin has been reduced from 15% to 3%, representing an actual pre-tax profit drop of 75% per ton of coal produced [6].

In the short term coal will be used directly as an energy source. Increased electric power production in the next decade has been projected to come from 170 new coal-fired, 20 new oil-fired, and 20 new gas-fired plants [7]. These plants represent represent a $60 billion investment. In addition, 170 nuclear plants ($110 billion) are foreseen.

In the middle term, alternative fuels from coal will begin to enter the market. Depending on the extent of Government subsidy, from zero [1] to twenty-six [8] commercial coal gasification plants are forecast by 1985 ($5 - $20 billion) producing up to six billion cubic feet per day. Table IIA1.3 is a summary of the National Petroleum Council's estimate of the potential growth of high Btu gas from coal. The projected production schedules represent about 15% of the expected supply-demand energy gap in 1985. To fill the gap completely would require approximately 140 plants ($30 billion) and 34 billion tons of coal [8]. The National Petroleum Council's estimate is somewhat optimistic compared to the Project Independence Report (Fig. IIA1.3). Coal liquefaction will lag gasification by 7-10 years [7]. Figure IIA1.4 illustrates the growth potential of synthetic liquid fuel production capacity for various scenarios. One hundred twenty-six potential plant sites have been identified in the United States [10] as having sufficient water and coal to support synthetic gas production of 250 X 10^6 ft^3/day for 34 years.

There are many proposed gasification and fewer liquefaction processes under study. Reference 11 summarizes the gasification processes. Liquefaction is discussed in References 8 and 12.

TABLE IIA1.3

Potential Growth of High Btu Gas from Coal* [9]

	Capacity Added (TCF/Yr.)	Cumulative Capacity (TCF/Yr.)	Millions of Dollars Invested: Plant	Strip Mines+	Total in Year	Total Cumulative
1975	0.08	0.08	210	40	250	250
1976	0.16	0.24	420	80	500	750
1977	0.16	0.40	420	80	500	1,250
1978	0.25	0.65	600	120	720	1,970
1979-1985	0.33‡	3.0	800‡	160‡	960‡	8,690

* Assumes existing technology and immediate accelerated rate of build-up

\+ Total mining capacity (strip) in 1985: 225 to 250 million tons per year (8 to 9 billion tons reserves).

‡ Each year.

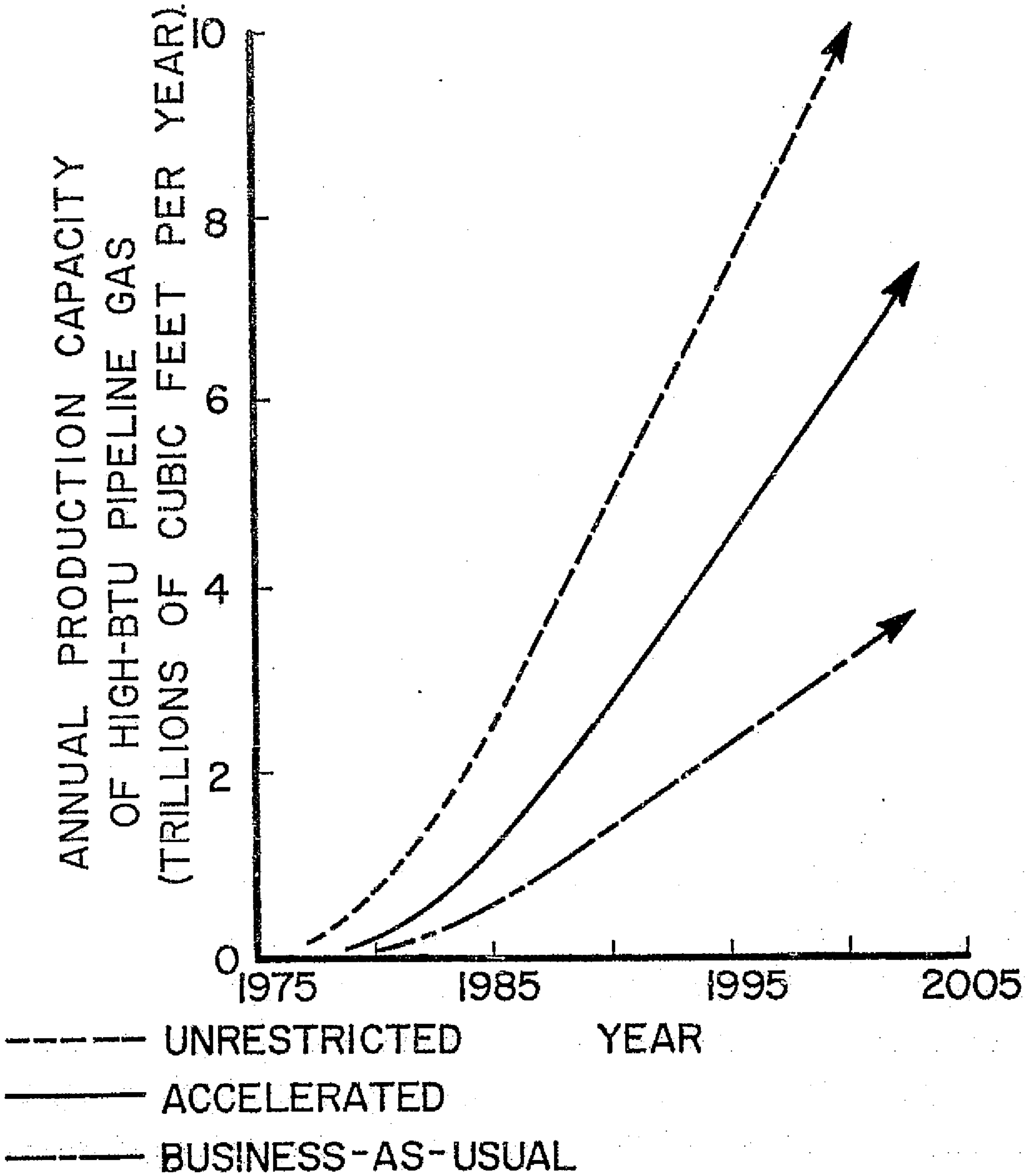

Figure II A1.3
Predicted Growth of Synthetic High-Btu (Pipeline) Gas Annual Production Capacity [1]

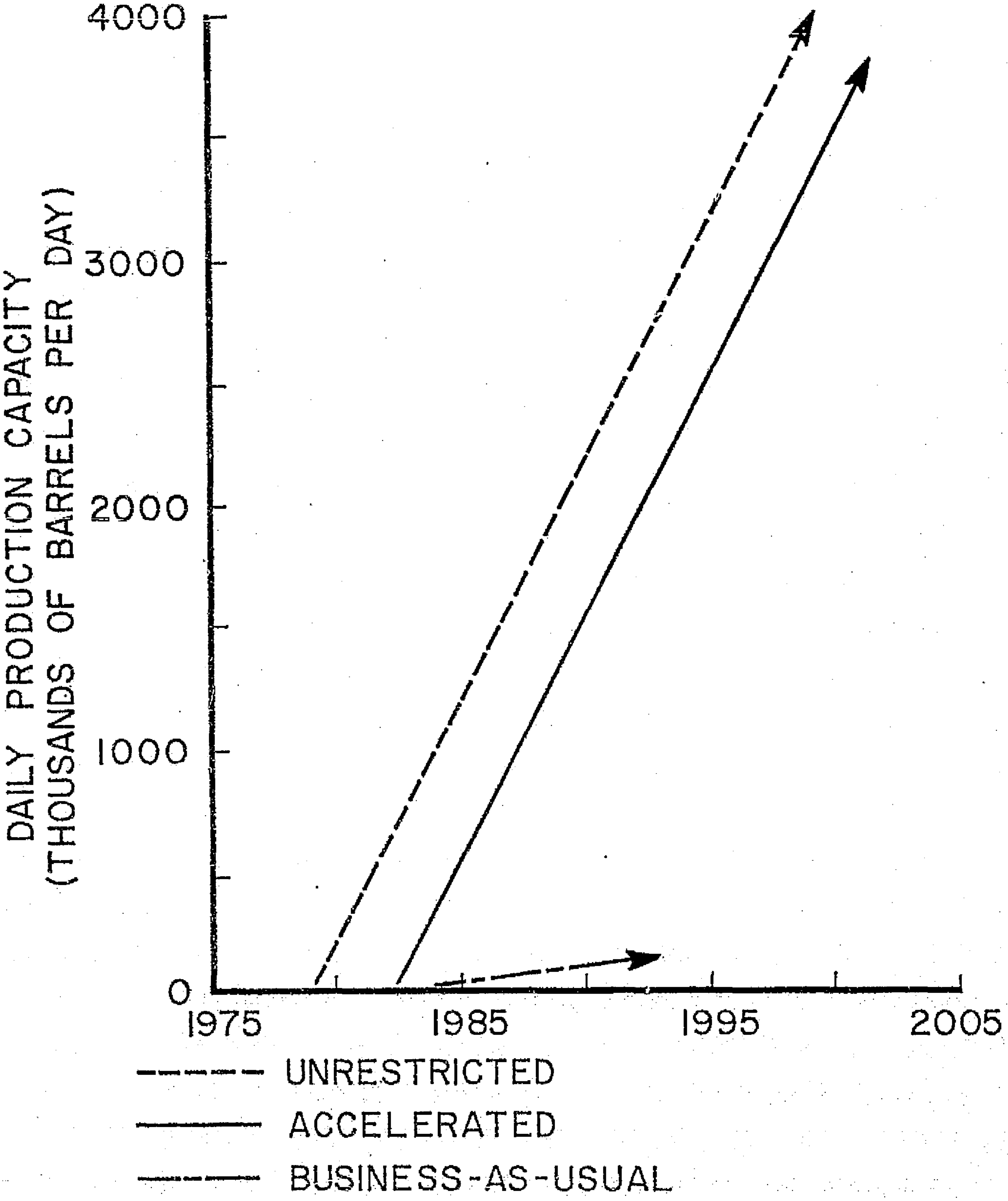

Figure II AI.4

Predicted Growth of Synthetic Liquid Fuel Daily Production Capacity [1]

Realistic cost estimates for synthetic natural gas (SNG)[high quality (1000 Btu/ft^3) coal gas] ranges from $1. to $2./thousand ft^3 ($1. - $2./mm Btu) [1]. Table IIA1.4 is a compilation of the claims made for various gasification processes. Not all the processes are included but the ones listed are typical.

c. Location

Coal production has historically been centered in Appalachia. However, most of the proven reserves lie in the Midwest and Northern Great Plains [1].

Figure IIA1.5 depicts the coal fields of the United States and distinguishes between surface and underground mining.

Figure IIA1.6 indicates the distribution of coal by grade across the United States. Tables IIA1.5 and IIA1.6 relate United States' underground and surface coal reserves and production by regions.

Table IIA1.7 lists selected comparisons of mapped and unmapped resources of coal.

Figure IIA1.7 summarizes the general location of recoverable resources of all coal and of low sulfur coal.

The projected distribution of coal gasification sites in 1985 is given in Table IIA1.8. Reference 9 summarizes the status of U. S. coal gasification processes. Location and nature of the processes is also tabulated. Reference 17 gives a lengthy summary of all coal gasification methods, their advantages, disadvantages and capital and operating costs.

d. Limitations

Reference 1 states that 90 percent of strip mineable coal can be recovered, and about half of the underground reserves are mineable using current technology. In addition, present sulfur emission standards make

TABLE IIA1.4

Energy Cost For Coal Gas

Type of Gas	Process	Coal Used - Type and/or Price ($/ton)	Gas Energy Content (Btu/mm Ft^3)	Cost $/mm Btu
SNG	Lurgi [13,14]	Bituminous Western Scotland	980 980 980	1.50 1.20 0.70 - 0.90
Inter-mediate Btu Gas	Kellogg [15]	Bituminous-20	300	1.66
	CO_2-acceptor [11]	Lignite	375	3.00
	Koppers-Totzek [5]	Eastern -10 Illinois -7 Western -4	300 300 300	1.00 0.90 0.75
Low Btu Gas	ATGAS [11]	5-7	n.a.	0.90 - 1.10
	Kellogg [15]	Bituminous-20	150	1.27
	Winklers [9]	Lignite	110 - 140	0.75 - 0.90
Hydrogen	Gasification+ shift conversion [21]	12.50 7-8	300 300	1.50 - 2.00 1.10 - 1.50

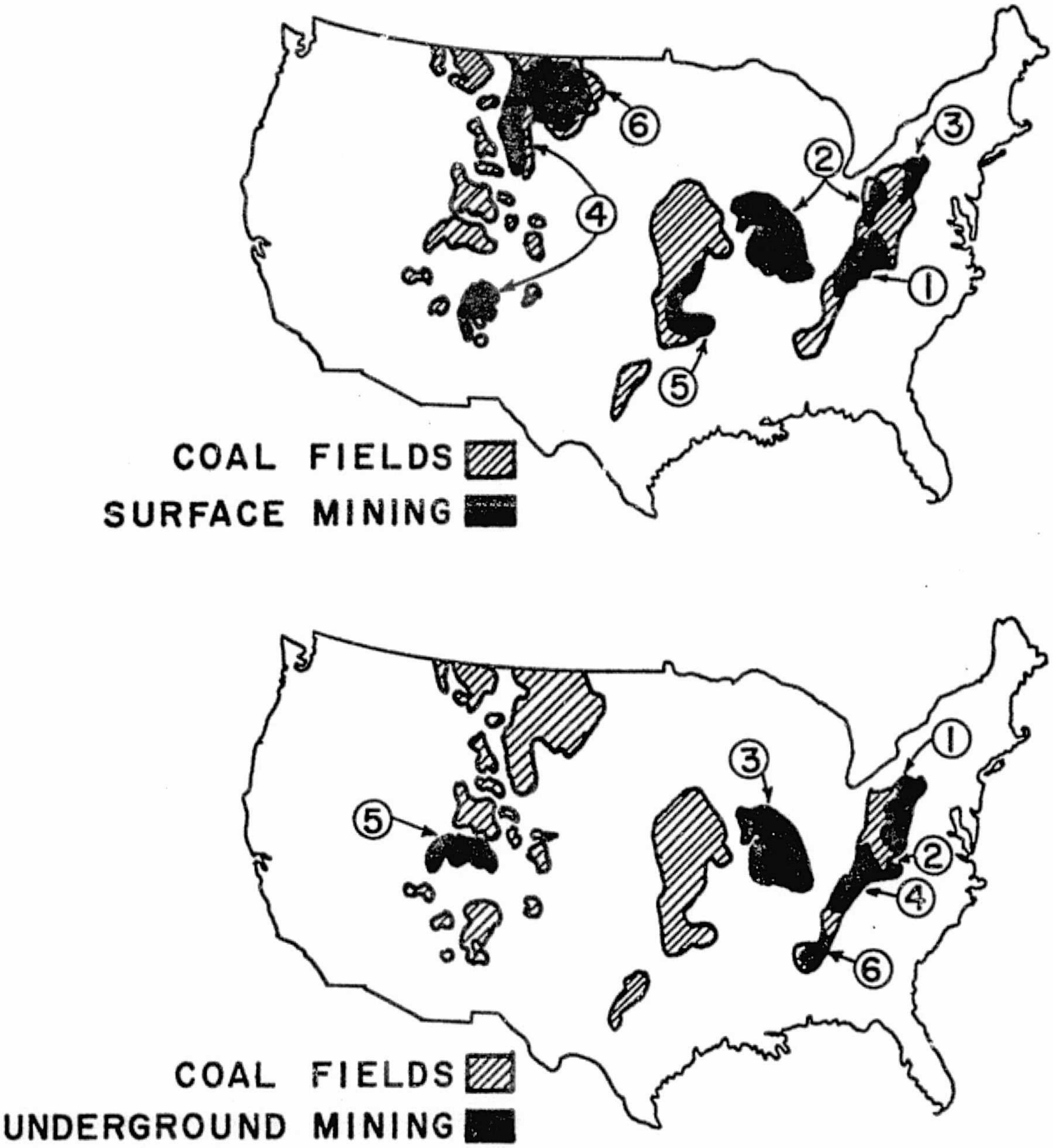

Figure II A 1.5

Geographical Distribution of Coal Resources of the United States [2]

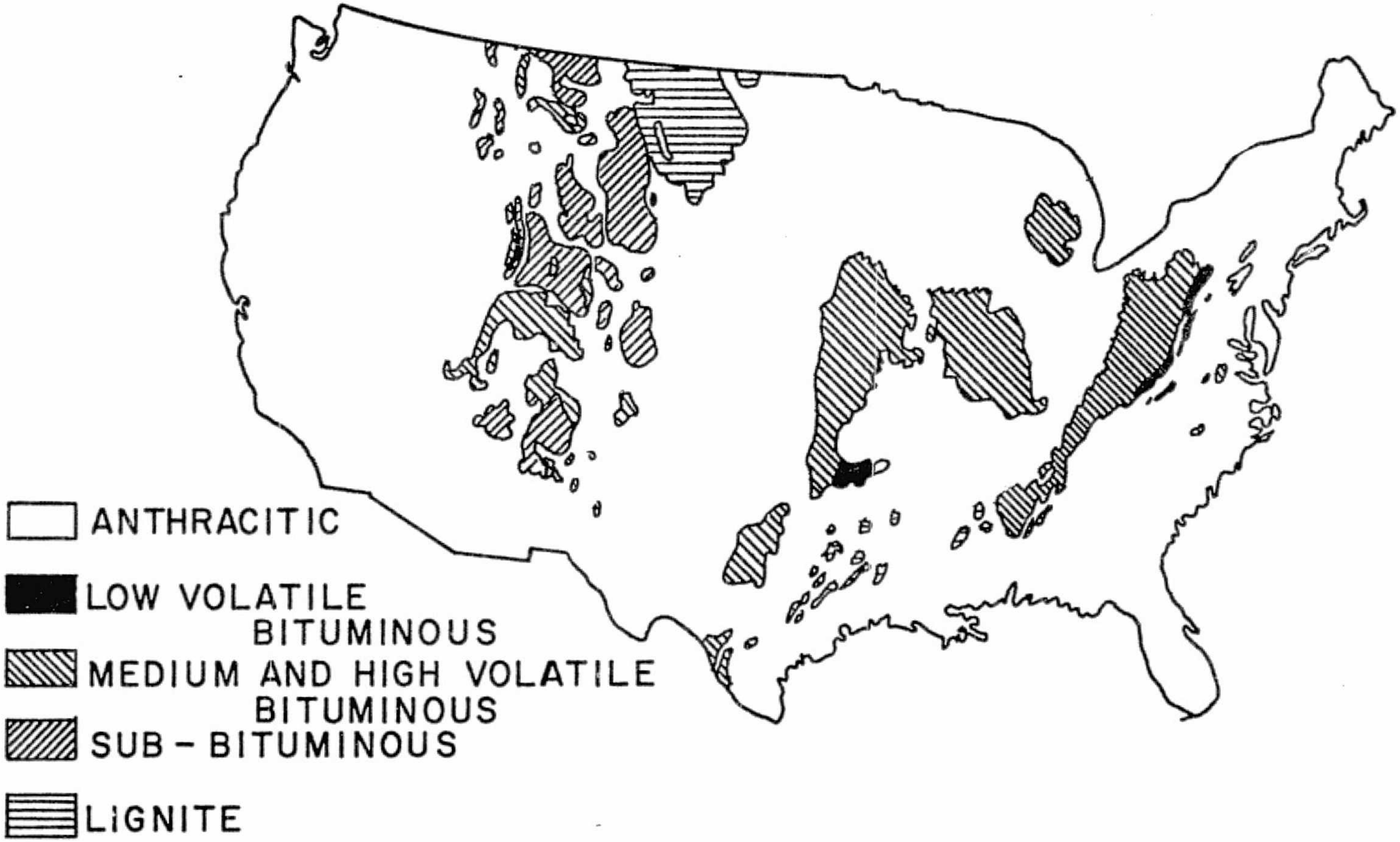

Figure II A I.6

Quality of Coal Resources of the United States [16]

TABLE IIA1.5

United States Surface Coal Reserves and Production [2]

Region*	Recoverable Reserves (billion tons)	(Q)+	1970 Production (million tons)	Life of Reserves (years) at % Growth Rates 0%	3%	5%
1	4.2	120	101.2	42	27	23
2	5.6	155	91.0	62	36	29
3	0.8	24	25.1	32	23	19
4	23.8	720	19.1	1246	122	85
5	1.6	20	8.3	193	65	48
6	2.0	60	5.6	375	85	62
Other	6.1	180	13.8	500	95	67
Total	45.0	1330	264.1	170	61	46

* See Fig. IIA1.5

\+ 15 mm Btu/ton for Western coal and 30 mm Btu/ton for Eastern coal

TABLE IIA1.6

United States Underground Coal Reserves and Production [2]

Region (1)	Remaining measured and Indicated reserves (2) (billion tons)	(Q)(5)	Economic available Reserves (3) (billion tons)	(Q)	Recoverable Reserves (4) (billion tons)	(Q)	1970 Production (million tons)	Life of Reserves at % growth rate 0%	3%	5%
1	92.7	2800	67.1	2000	33.5	1000	145.8	230	69	50
2	9.1	270	9.1	270	4.6	140	N.A.	-	-	-
3	83.1	2500	59.5	1800	29.7	900	52.3	568	96	68
4	34.5	520	24.4	370	12.2	180	95.0	129	52	40
5	21.9	330	13.3	200	6.7	100	8.6	774	106	74
6	1.6	43	0.6	20	0.3	10	9.1	35	23	20
Other	106.3	2300	35.2	760	17.6	350	N.A.	-	-	-
Total (6)	349.1	8763	209.2	5420	104.6	2680	338.8	309	80	58

(1) See Fig. IIA1.5
(2) Bituminous, subbituminous, and lignite in seams of "intermediate" or greater thickness and less than 1000 ft. overburden.
(3) Excludes lignite and "intermediate" thickness seams of bituminous and subbituminous coal.
(4) Based on 50% recovery of economically available reserves.
(5) 15 mm Btu/ton for Western coal and 30 mm Btu/ton for Eastern coal.
(6) May not add correctly due to rounding off.

Source: National Petroleum Council

TABLE IIA1.7

Selected Comparison of Mapped and Unmapped Resources of Coal [2]

	(billion tons)(Q)*		Mapped and Explored (billion tons)	Unmapped and Unexplored (billion tons)	Unmapped/ Total (Percent)
New Mexico	88	1600	61	27	31
Utah	80	1200	32	48	60
Colorado	227	3400	81	146	64
Wyoming	445	7000	120	325	73
Montana	379	6000	222	157	41
North Dakota	530	8000	350	180	34
Illinois	240	7200	140	100	42
Indiana	57	1800	35	22	39
Pennsylvania	80	2400	70	10	13
West Virginia	102	3000	102	-	0
Ohio	44	1320	42	2	5
Total	2272	35700	1255	1017	44.5

*15mm Btu/ton for Western coal and 30mm Btu/ton for Eastern coal.

TABLE IIA1.8

Projected Distribution of Coal Gasification Plants in 1985 [9]

	Case I*		Case II/III**		Case IV***	
	No. of Plants	TCF	No. of Plants	TCF	No. of Plants	TCF
			Bituminous Coal			
New Mexico	4.0	0.33	4.0	0.33	2.0	0.16
			Subbituminous Coal			
Wyoming	7.0	0.58	3.4	0.28	2.1	0.18
Montana	6.4	0.53	3.0	0.25	1.0	0.08
			Lignite			
Montana	8.0	0.66	3.6	0.29	0.0	0.00
North Dakota	4.6	0.38	2.0	0.16	1.5	0.12
TOTAL	30.0	2.48	16.0	1.31	6.6	0.54

*Case I. Maximum rate of buildup under special conditions and appropriate special policies.

**Case II and III. Rapid but practical buildup rate.

***Case IV. Minimum buildup rate foreseen on basis of current economics.

Source: National Petroleum Council

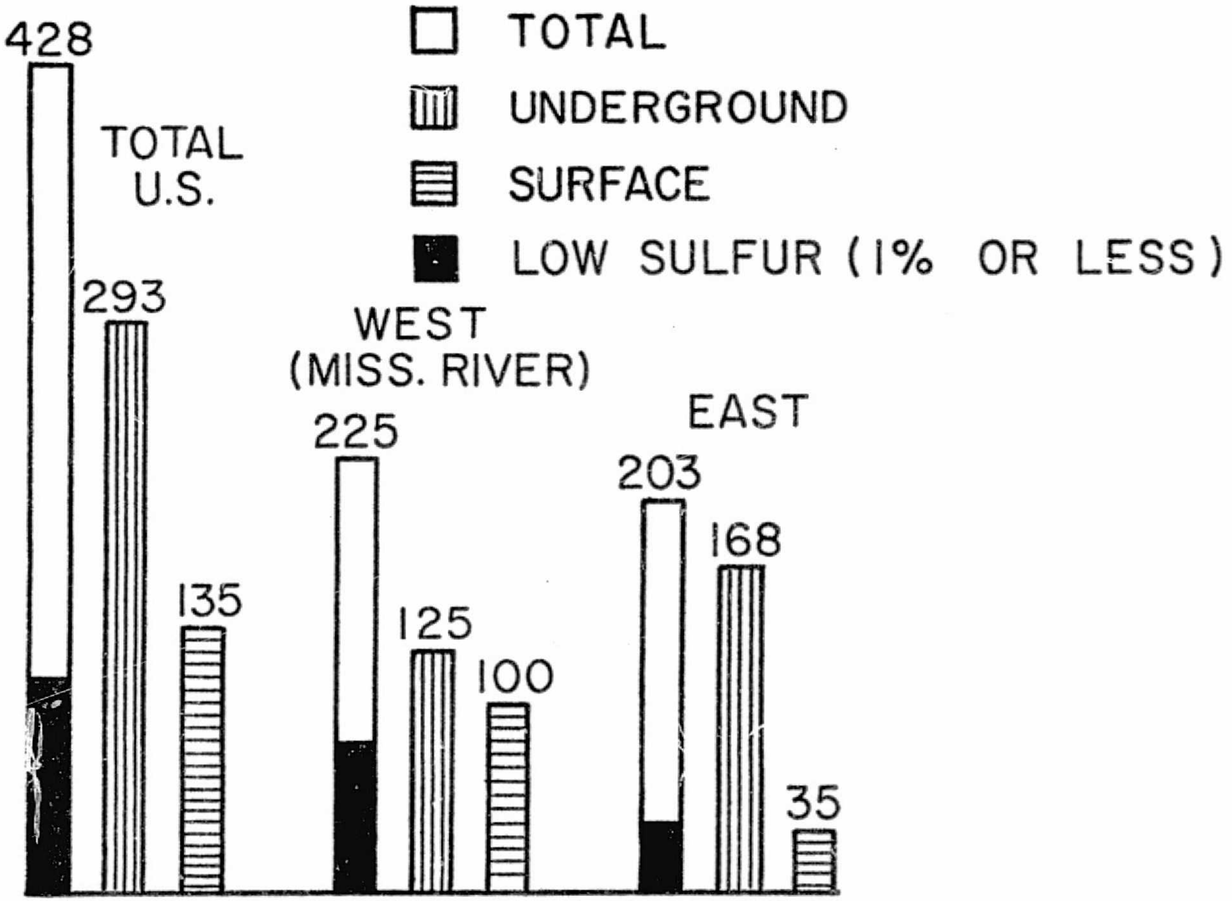

Figure II AI.7

United States Recoverable Coal Reserves [7]

only about 15 percent of Appalachian coal acceptable, and almost all Interior Basin coal unacceptable [8]. This accentuates the problem of energy transportation to the East coast and Midwest industrial areas. Coal is presently being shipped from Wyoming coal fields to Chicago at a rate of over 5-million tons per year.

Labor problems and the recent more stringent mine safety legislation pose difficulties for rapid coal expansion. Coal miners have long-standing grievances. In recent years, coal miners have averaged a 4-1/2 day work week [9]. To increase production, the labor disputes must be settled. A 5-day work week would increase production by 50-million tons per year (1.3 Q/yr.). Rising labor costs have encouraged strip-mining, which can produce three times the coal per man-hour of underground mines. The more stringent regulations have caused the closing of many smaller underground mines.

Water scarcity will limit use of Western strip-mined coal. An NAS study [20] indicates that many strip-mine areas receive less than 10 inches of rainfall annually, and that in addition the soils in these areas cannot retain moisture. In such areas, reclamation of the land is not feasible. Only about 60 percent of the mineable coal is in areas where reclamation _is_ feasible.

Further, water scarcity in the Western areas is such that large scale gasification, liquefaction or power generation is not possible in even those areas where reclamation is possible [20].

A final difficulty for increasing coal use is removing sulfur from coal [2]. No preuse removal method is available since the sulfur is chemically bound. Many firms are attempting to perfect SO_2 removal methods for stack gases [22].

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2. Natural Gas

a. National Reserves

Considerable controversy exists over United States' reserves of natural gas and petroleum [1]. The U. S. Geologic Survey estimates tend to be considerably higher than other sources. The March 1974 USGS estimates of undiscovered recoverable natural gas are given as between 1,000 and 2,000 trillion cubic feet (1,000 to 2,000 Q). An estimate by Mobil Oil based on probability profiles of the 14 U. S. oil districts yields an estimate of 443 trillion cubic feet (450 Q). These estimates are for the continental U. S., including offshore and Alaska. Reference 2 claims that the U. S. has undiscovered natural gas equal to more than 50 times current annual marketed production, or about 1100 Q.

Figure IIA2.1 summarizes three different estimates of future United States natural gas supply in the 48 contiguous states and adjacent offshore.

Reference 3 estimates that an additional 240-300 trillion cubic feet (250 Q) may be available in the Green River, Piceance and Uinta Basins of the Rocky Mountains. This gas may be available by the 1990's at 2-7 trillion cubic feet a year. However, recovery of this gas will depend on such new recovery techniques as underground nuclear stimulation or massive hydraulic fracture.

Figure IIA2.2 illustrates the chronicle of the relationship between proved reserves, annual additions and production. Particularly noteworthy is the trend of the last seven years. Resource depletion estimates are illustrated in Table IIA2.1 and Figure IIA2.3. Figure IIA2.3 is based on the method of Section I, using a 1972 U. S. production rate of 22.1 Q/yr. from reference 4, minimum reserves of 450 Q and

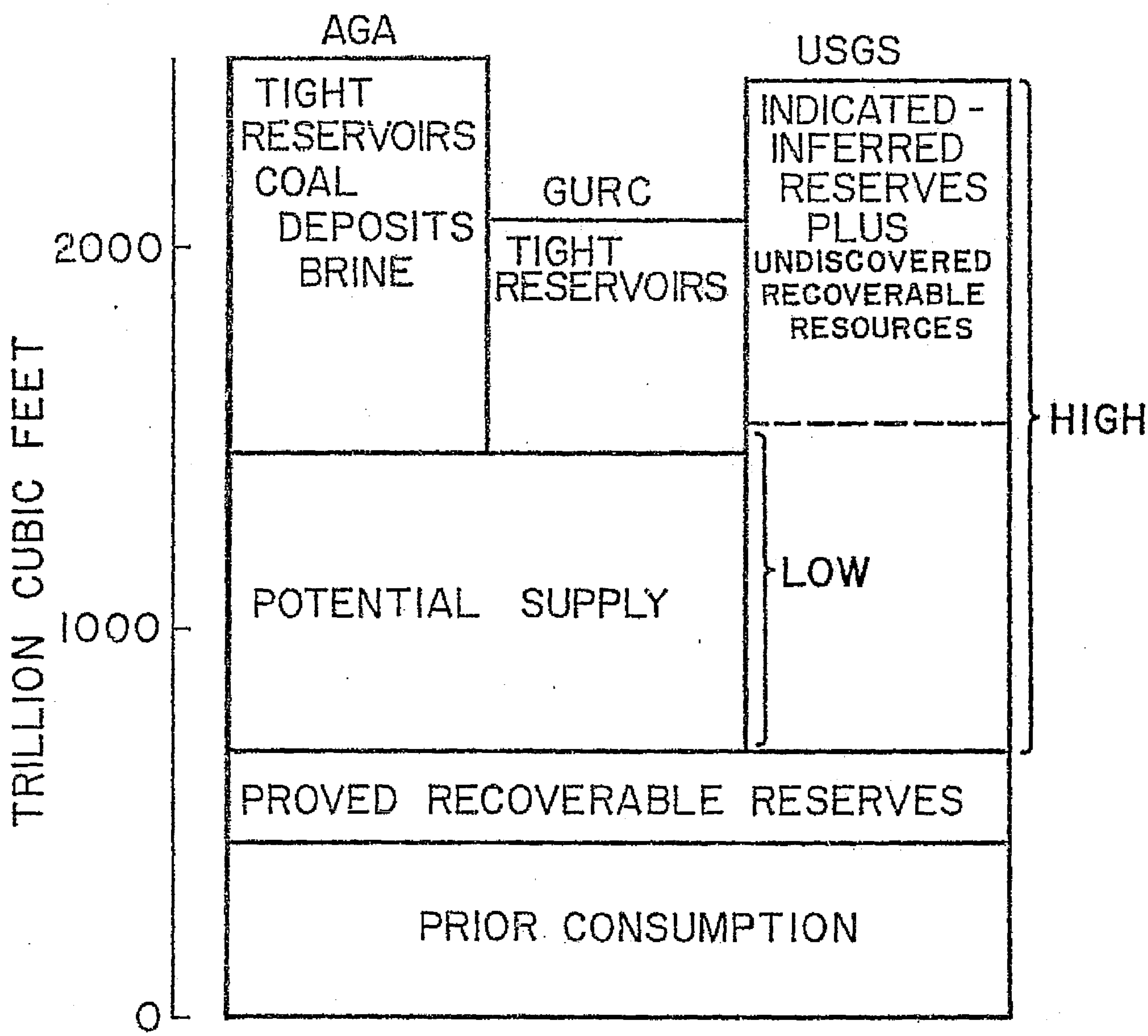

Figure II A2.1

Comparison of Predictions of Potential Recoverable Natural Gas Resources [3]

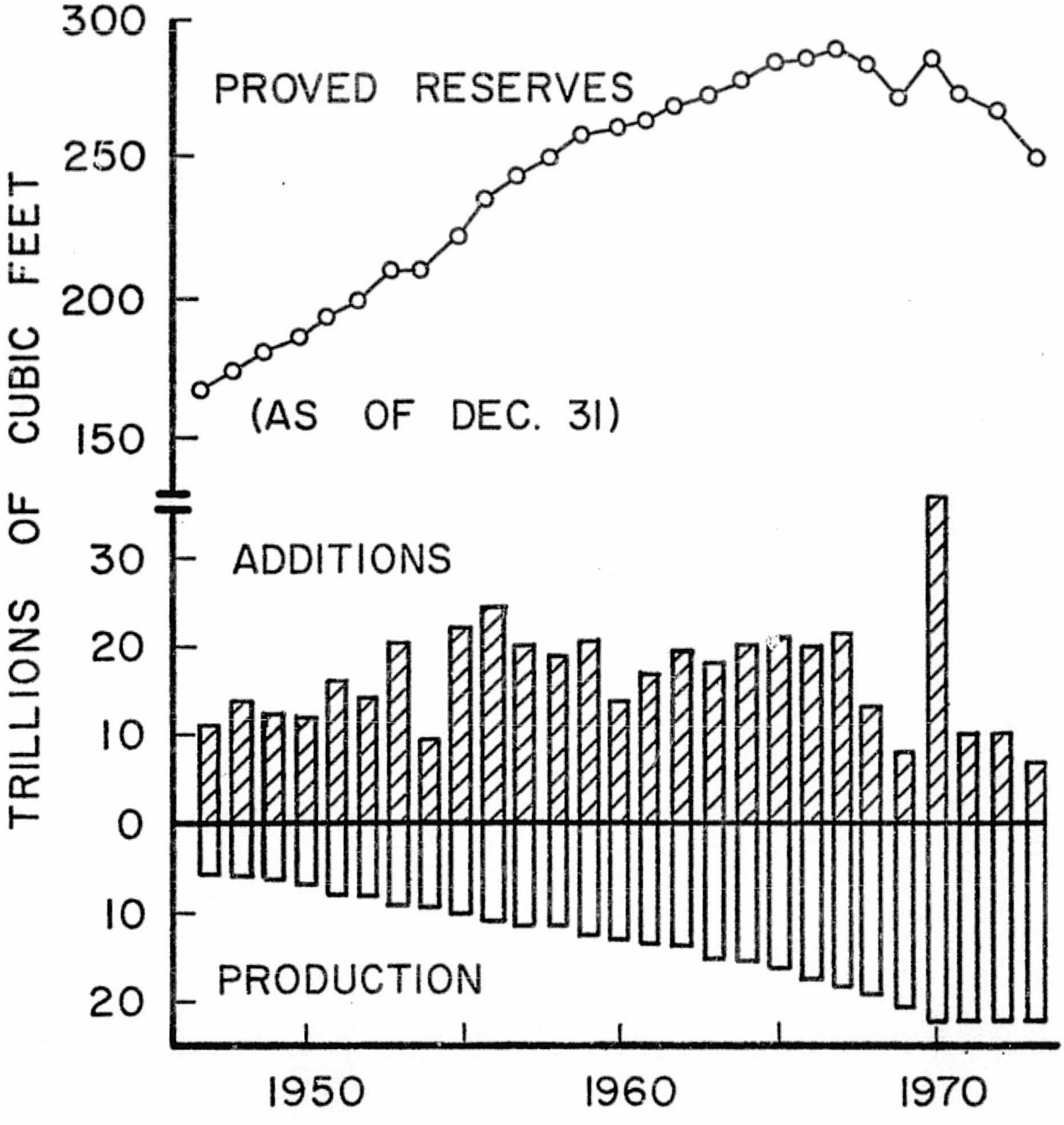

Figure II A2.2

Natural Gas Production, Proved Reserves, and Additions to Proved Reserves through 1973 [4]

TABLE IIA2.1

Resource Depletion Estimate for Coal For Various Scenarios [5]

	Year in Which All Ultimately Recoverable Resources Are Depleted			
	Low Estimate		High Estimate	
	EGM(a)	RGM(b)	EGM	RGM
No Imports, no synthetic Fuel	1989	1991	2000	2007
No Imports, synthetic Fuel	1990	1992	2008	2016
Imports, no synthetic Fuel	1993	1997	2010	2025
Imports, synthetic Fuel	1996	2000	2037	2050+

(a) Exponential Growth Model

(b) Reduced Growth Model

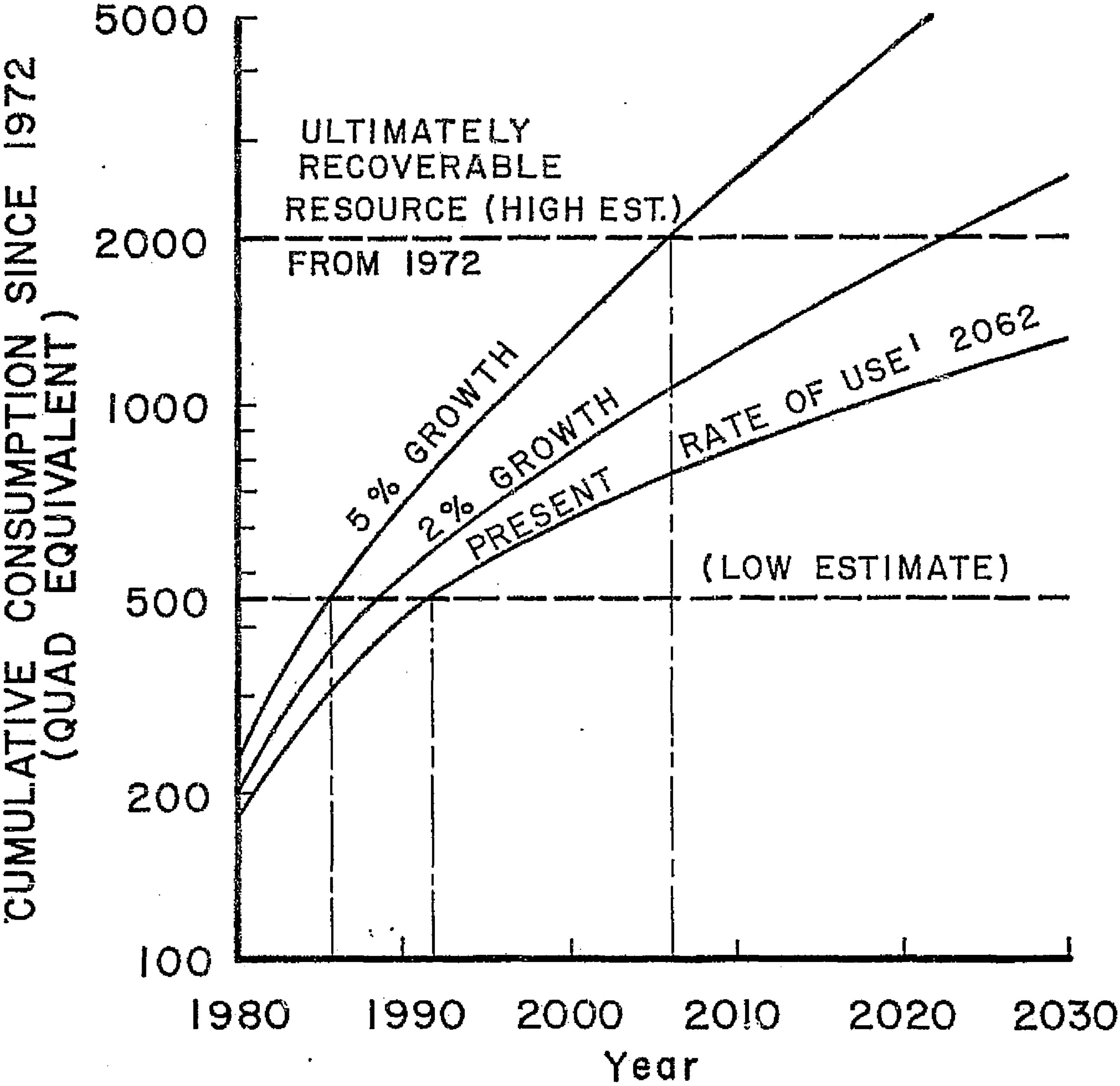

Figure II A 2.3

Life Expectance of Natural Gas Reserves

[1]1972 Production: 22.1 Q/yr

maximum of 2000 Q.

Recovery of gas, incidentally, is much higher than for petroleum, efficiencies running as high as 70-80 percent [6].

b. Cost

The average wellhead price of natural gas since 1945 is tabulated in Table IIA2.2. However, in the past, the wellhead price, especially with artificial government price regulation, has had little bearing on the ultimate consumer price of natural gas. Of the four stages in the delivery of gas to the consumer -- production, storage, transmission and distribution -- it is the latter three, the wellhead-to-burner-tip system, that usually had the largest impact on consumer price [7]. One of the attractive features of natural gas is its ease and efficiency of transmission in high pressure underground pipelines. This cost is relatively fixed. Storage has been the main variable in the cost equation. Underground storage is desireable but many times unavailable. Significant capital investment is often required for storage facilities. This fact has made the cost of natural gas sensitive to the money markets. Liquefaction is one way to economize on storage. Liquefaction represents a 600 to 1 contraction. High pressure storage can achieve up to a 200 to 1 contraction. Liquefaction, of course, can help on the transmission side where pipelines are not available (because not enough market is available to justify one) or not practical (such as for continent-to-continent transmission).

The energy pinch will bring a new economics to the costing of natural gas. The current national ceiling on natural gas is 42¢ per thousand cubic feet, or about 42¢ per million Btu [8]. No one expects

TABLE II A2.2

Marketed Production of Natural Gas and Average Wellhead Price
1945-1972 [4]

YEAR	MARKETED PRODUCTION MILLIONS OF CUBIC FEET	TRILLIONS OF Btu	AVERAGE WELLHEAD PRICE (CENTS PER MCF)
1945	4,049,002	4,481.7	4.9
1950	6,282,660	6,753.0	6.5
1951	7,457,359	8,016.7	7.3
1952	8,013,457	8,614.5	7.8
1953	8,396,916	9,026.7	9.2
1954	8,742,646	9,398.2	10.1
1955	9,405,351	10,110.4	10.4
1956	10,081,923	10,838.2	10.8
1957	10,680,258	11,481.0	11.3
1958	11,030,248	11,857.5	11.9
1959	12,046,115	12,919.5	12.9
1960	12,771,038	13,728.8	14.0
1961	13,254,025	14,248.1	15.1
1962	13,876,622	14,917.4	15.5
1963	14,746,663	15,852.7	15.8
1964	15,462,143	16,621.8	15.4
1965	16,039,753	17,242.7	15.6
1966	17,206,628	18,497.1	15.7
1967	18,171,326	19,534.2	16.0
1968	19,329,600	20,771.0	16.4
1969	20,698,240	22,250.6	16.7
1970	21,920,642	23,564.7	17.1
1971	22,493,017	24,180.0	18.2
1972	22,531,698	24,221.6	18.6

this price to hold. The Federal Government recently sold leases in the Gulf of Mexico for oil and gas exploration. The amount paid in the competitive bidding was estimated to represnet a wellhead price of 60¢/thousand cubic feet when production begins in 1976 and to uniformly escalate to $1.75/thousand cubic feet by 1986. This new price structure is in line with the anticipated price of synthetic natural gas from coal discussed earlier.

The nuclear or hydraulic stimulation of wells in the Rocky Mountains may result in significant gas production by the 1990's at a price projected to be between 17¢ and 74¢/thousand cubic feet [3] (1972 dollars). To develop the massive hydraulic fracture technique for production beginning in 1980 and the nuclear stimulation technique for production beginning in 1988, it is estimated that annual investments of $1/3 to $1 billion (1972 dollars) will be required.

The so-called Arctic Gas system, the proposed pipeline which will transport Alaska's natural gas to the lower 48 states, will cost in the neighborhood of $10 - $12 billion in 1974 dollars [9].

c. Location

The natural gas reserves by general location are shown in Table IIA2.3.

Table IIA2.4 illustrates the ultimately discoverable natural gas reserves of the United States.

Reference 11 tabulates the fossil fuel yield of the outer continental shelf of the U. S. for the last 20 years.

Reference 12 tabulates the number of gas wells, the drilling activity in 1973 and the estimated reserves by state and district.

TABLE IIA2.3

Undiscovered Recoverable Natural Gas
(Trillions of Cubic Feet or Q) [6, 8]

LOCATION	USGS (March 1974) Low	High	Mobil Expected Value	NPC
		ONSHORE		
Alaska	105	210	104	272*
Lower 48 States	500	1000	65	550
Subtotal Onshore	605	1210	169	822*
		OFFSHORE		
Atlantic	55	110	31	55
Alaska	170	340	105	-*
Gulf of Mexico	160	320	69	156
Pacific Coast	10	20	69	3
Subtotal Offshore	395	790	274	214*
TOTAL U. S.	1000	2000	443	1036

* NPC tables do not separate on-and-offshore Alaskan oil.

TABLE IIA2.4

Ultimately Discoverable Volumes of Natural Gas in the United States [10] (Trillion Cubic Feed)

Area*	(a) Cumulative Production**	(b) Proved Reserves***	(c) Production Plus Reserves (a+b)	(d) Potential Supply	(e) Ultimately Discoverable (c+d)
A	30	6	36	102	138
B	4	2	6	60	66
C	1	2	3	9	12
D	49	15	64	90	154
E	79	72	151	140	291
G	80	56	136	125	261
H	12	8	20	59	79
I	8	8	16	18	34
J-North	99	36	135	84	219
J-South	44	25	69	61	130
L	26	5	31	32	63
48 State subtotal	432	235	667	780	1447
K Alaska	1	31	32	366	398
TOTAL U.S.	433	266	699	1146	1845

*See Fig. IIA2.4

**Excluding stored gas

***Including stored gas

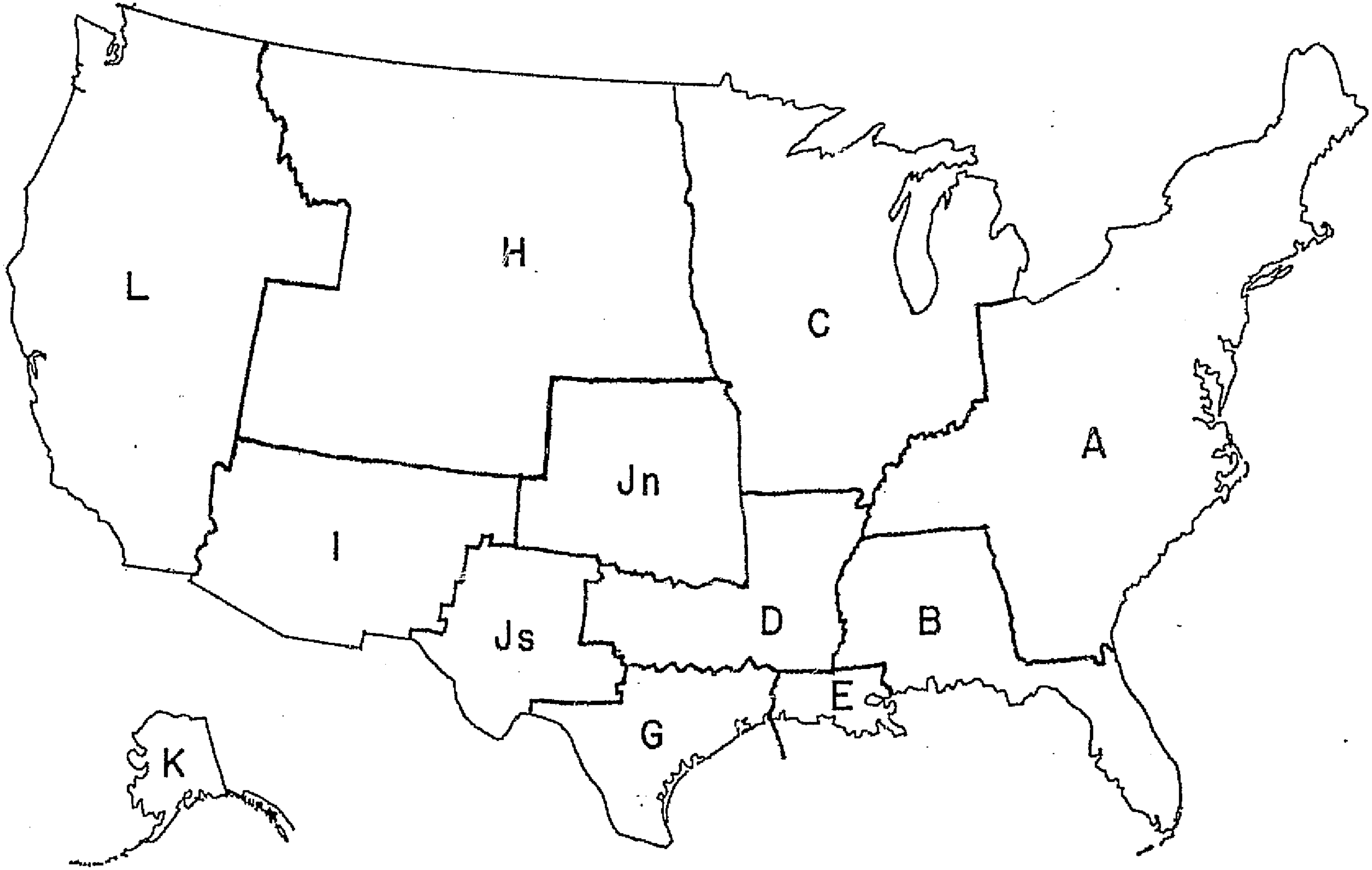

Figure II A 2.4

Natural Gas Regions in the United States

(See Table IIA 2.4)[10]

A detailed map of the Gulf of Mexico lease tracts are found in reference 8. Also included are tabulations by states of each tract.

A map of the three major geological formations in the Rocky Mountains which are claimed to have the potential of doubling the total United States natural gas reserve using new recovery techniques is given in reference 3.

d. Limitations

Natural gas is a clean burning, easily transported high energy content fuel; i.e., it is just about the perfect fuel. This fact together with government price control has made it very attractive as an energy source. The deflated price has unfortunately discouraged exploration. Large demand and low discovered supply has led us to the present low reserve situation.

The only limitations to its use are ultimate supply which will depend to some extent on the regulated price. As pointed out in the Cost section, most people believe the price must rise.

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3. Petroleum

a. National Reserves

Some controversy exists over the figures of the U. S. Geological Survey [1]. USGS figures for total undiscovered recoverable oil and natural gas liquids in Alaska and the lower 48 states, including offshore reserves, total between 200 and 400 billion barrels (1160 to 2320 Q's). Mobil Oil's prediction places the expected value of remaining discoverable reserves at 88 billion barrels (510Q). The National Petroleum Council figures for 1970 [2] show ultimate discoverable oil-in-place of 810.4 billion barrels (4700 Q) of which 425.2 billion barrels (2466 Q) had been discovered to January 1, 1971, leaving 385.2 billion barrels (2234 Q) of remaining discoverable oil. These figures include offshore and Alaskan oil. Present (1971) proved reserves were 38 billion barrels (220 Q).

Figure IIA3.1 summarizes the estimates of recoverable crude oil reserves.

Merklein [3] has examined the amount of oil ultimately recoverable from these reserves using primary, secondary and tertiary recovery methods, and gives the figures as 18 percent by primary recovery through the artificial lift stage, and secondary recovery and additional 18 percent. Tertiary recovery by in-situ combustion may ultimately allow an additional 33 percent for a total ultimate recovery of 68 percent.

Domestic United States crude production for 1973 averaged 9.2 million barrels per day, down 2.9% from 1972 and 8% from the peak year of 1970 [4].

A reserve depletion estimate for different use rates is given in Figure IIA3.2 using the method of Section I. The reference production

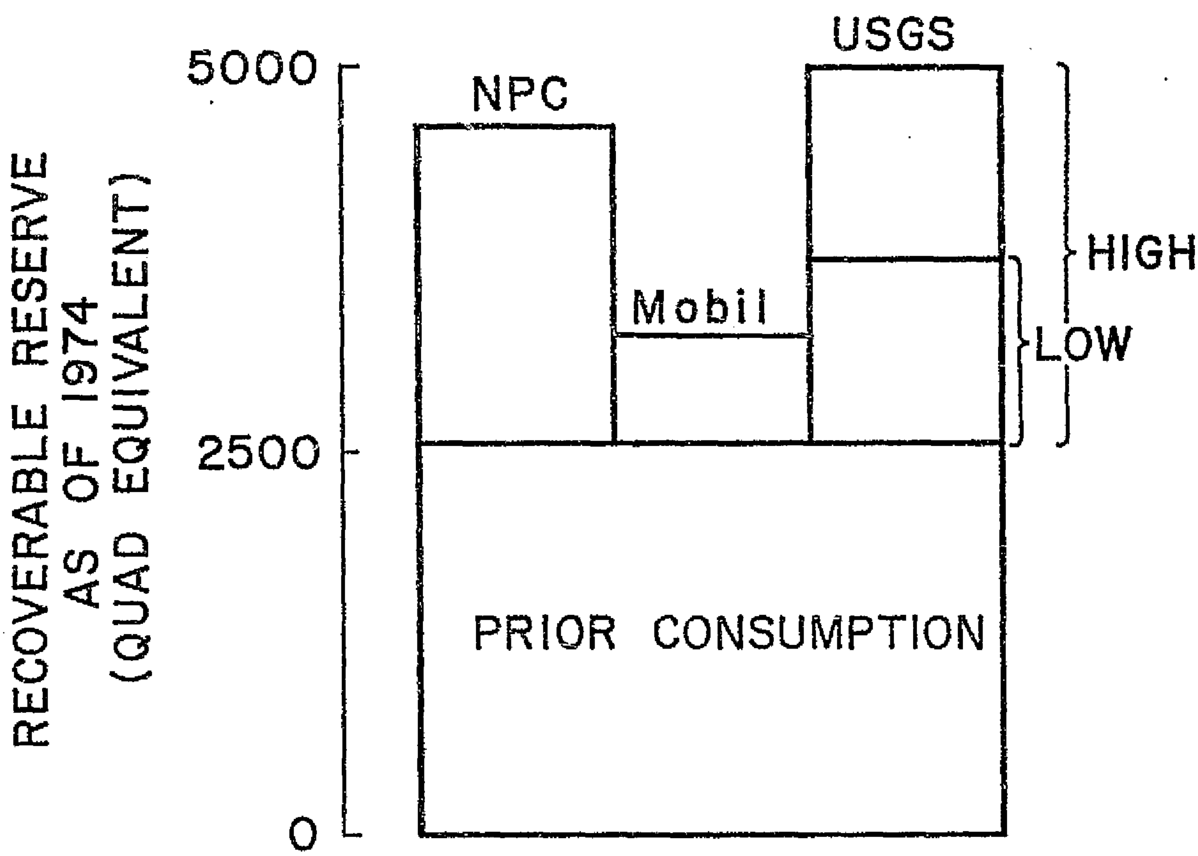

Figure II A3.1

Comparison of Predictions of Recoverable Crude Oil Reserves

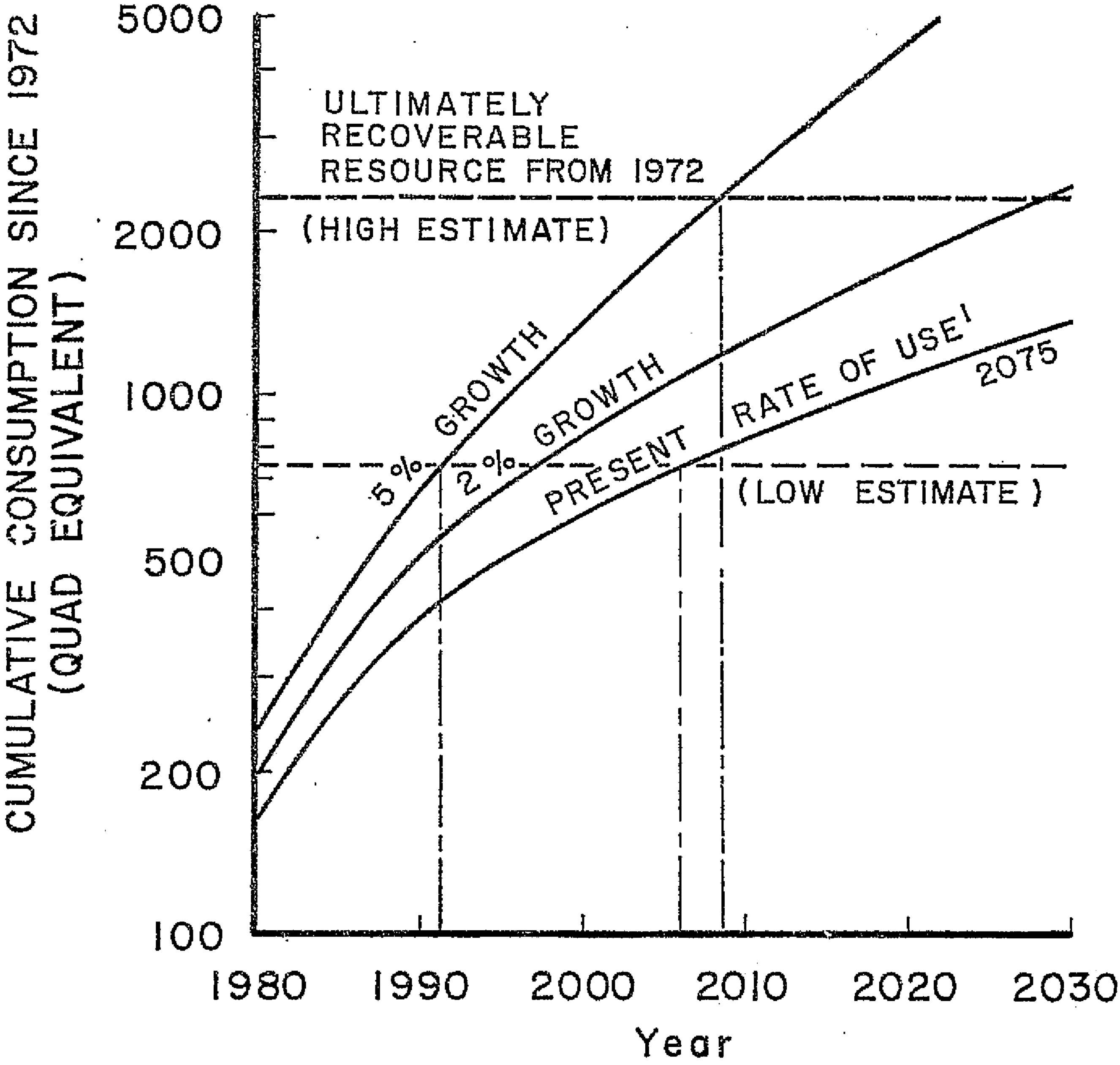

Figure II. A 3.2

Life Expectance of Oil Reserves

[1] 1972 Production: 22.4 Q/yr

rate used is for 1972, given as 22.4 Q/yr. by reference 10. A lower limit of 730 Q (Mobil's 510 Q remaining undiscovered plus the 220 Q proved reserves) and an upper limit of 2320 Q are assumed. Table IIA3.1 tabulates the petroleum resource depletion estimates for various scenarios.

Figure IIA3.3 illustrates the chronicle of United States proved reserves of oil and the yearly comparison of new oil and production for the last twenty years. The alarming fact, as was pointed out earlier for natural gas, is the proved reserves depletion since 1970. On the plus side more wells were completed in the United States in 1974 than in any year since 1967. For the first six months of 1974 32,104 wells were drilled (up 23% from 1973) and 161 million feet of hole were drilled (up 20% from 1973) [6].

b. Cost

When the posted price of a commodity can quadruple in one month at the whim of a small group of countries, it becomes obvious that any attempt to speculate on its future market price is useless. In February, 1970, the U. S. Cabinet Task Force on Oil Impact Control reported "we do not predict a substantial price rise in world oil markets over the coming decade" [7]. The price was then $2.00 per barrel. At present the price of crude oil varies from about $4 to $16 per barrel depending not only on where the oil came from but also when the producing well was drilled. For example [8] the December, 1974 posted price for nonexempt ("old") 20-20.9° California oil from the Signal Hill field was $4.15 a barrel. At the same time the asking (and apparently selling) price of exempt ("new") 20-20.9° Signal Hill oil was $10.32 a barrel. Similarly, exempt Alaskan oil fob California was selling at $10.50 a barrel, while nonexempt Alaska oil had a posted price of $4.65.

TABLE IIA3.1

Petroleum Resource Depletion Estimate for Various Scenarios [5]

	Year in Which All Ultimately Recoverable Resources are Depleted			
	Low Estimate		High Estimate	
	EGM(a)	RGM(b)	EGM	RGM
No Imports, no synthetic fuel	1988	1988	2011	2014
No Imports, synthetic fuel	1989	1989	2027	2030
Imports, no synthetic fuel	2001	2003	2031	2038
Imports, synthetic fuel	2006	2008	2050+	2050+

(a) extrapolated growth model

(b) reduced growth model

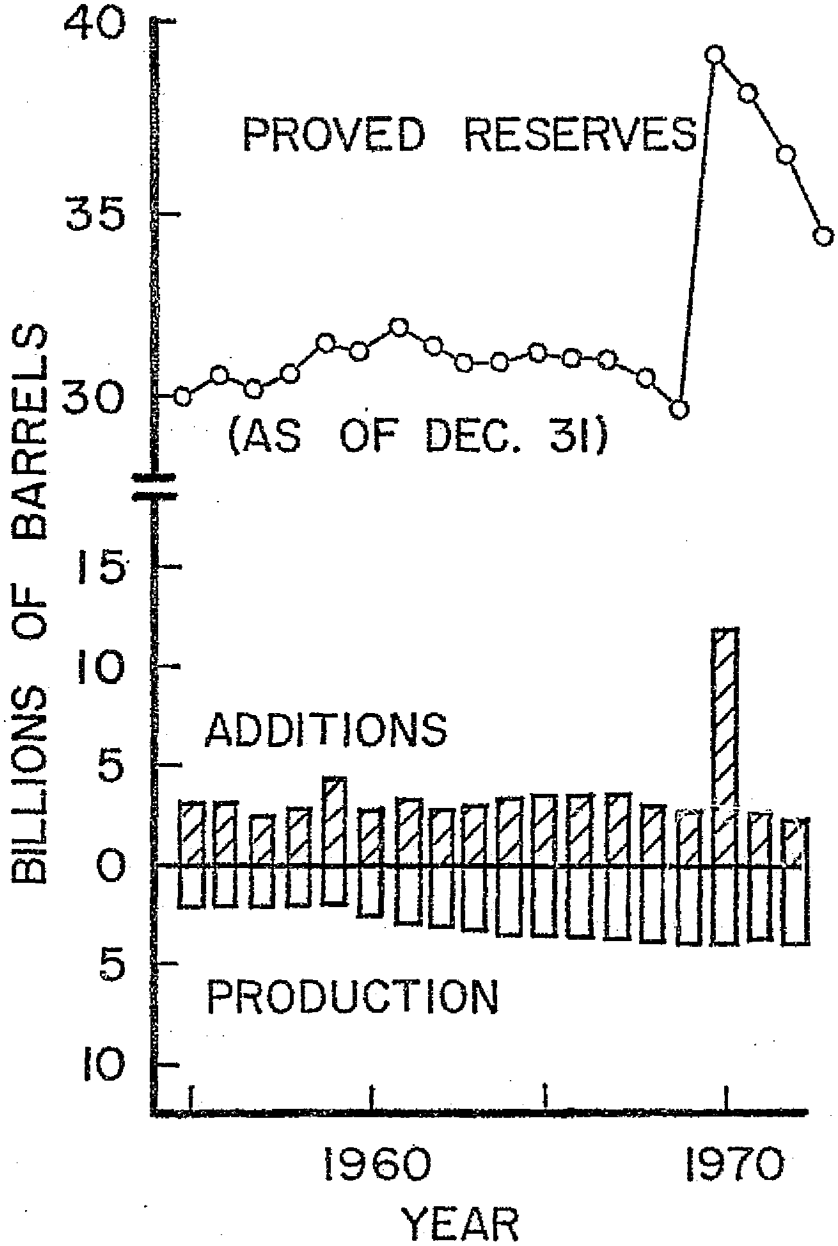

Figure II A3.3

Oil Production, Proved Reserves, and Additions to Reserves Through 1973 [2]

Since the market price of oil is so speculative, the only cost analysis of merit must be based on actual production costs. Table IIA3.2 summarizes the approximate 1972-1973 cost of producing crude oil or its energy equivalent from various areas or by various methods. The capital cost excludes escalation and interest. The technical unit cost at the wellhead includes exploration and lifting cost but excludes carriage, taxes, producing government's rent and production company's profit. It is clear from the table that the holders of large reserves of low technical unit cost oil can exert enormous leverage. This results in a virtual monopoly. From now on it is a matter of what the market will bear. Oil in the ground will appreciate faster than would invested oil revenues.

c. Location

The regional breakdown of United States' oil is given in Tables IIA3.3 and IIA3.4.

The drilling activity for 1973 and the first half of 1974 are summarized by state and region in reference 6. Expectations are high for the new leases on the continental shelf in the Gulf of Mexico, especially one tract (Destin anticline) 40 miles southwest of Panama City, Florida [11]. Work is currently beginning on the pipeline to bring Alaskan petroleum south. Current projections for completion of the trans-Alaskan pipeline from Prudhoe Bay to Valdez is 1977 [12]. A general review of Arctic and Arctic-related pipelines is given in reference 13.

TABLE IIA3.2

Approximate Costs of Producing Crude Oil or Its Energy Equivalent, 1972-1973 [7]

Energy Source	Capital Cost ($/(bbl/day))	Technical Unit Cost ($/bbl)
Persian Gulf	100-300	0.10-0.20
Nigeria	600-800	0.40-0.60
Venezuela,* Far East, Australia	700-1,000	0.40-0.60
North Sea, most other Europe	2,500-4,000	0.90-2.00
Large deep-sea reservoirs	over 3,000?	2.00-?
New U.S. reservoirs (not too remote)	3,000-4,000	1.70-2.50
Easier part of Alberta tar sands	4,000-8,000	2.00-3.00
High-grade oil shales	4,500-9,000	3.00-4.50
Gas synthesized from coal	5,500-8,000	3.00-6.00
Liquid synthesized from coal	6,000-9,500	3.00-6.00
Liquefied natural gas (landed)	6,000-10,000	3.00-6.00
Nuclear fission (light-water reactor)	20,000-30,000	?

* Excluding heavy oils

TABLE IIA3.3

Undiscovered Recoverable Oil and Natural Gas Liquids [1, 9] (Billions of Barrels)

LOCATION	USGS LOW	USGS HIGH	MOBIL	NPC
ONSHORE				
Alaska	25	50	21	48*
Lower 48	110	220	13	177
Subtotal Onshore	135	270	34	225*
OFFSHORE				
Atlantic	10	20	6	14
Alaska	30	60	20	71*
Gulf of Mexico	20	40	14	27
Pacific Coast	5	10	14	48
Subtotal Offshore	65	130	54	160*
TOTAL U.S.	200	400	88	385

*NPC does not classify Alaska in same manner as other sources. Onshore is North Slope only. Offshore includes all Alaska plus South Alaska onshore.

TABLE IIA3.4

United States Resources of Oil in Place [2]

Region*	Ultimate discoverable oil-in-place	Oil-in-place discovered to 1/1/71	Remaining discoverable oil-in-place Billion barrels	% of ultimate
	billion barrels			
Lower 48 states-onshore				
2 Pacific Coast	101.9	80.0	21.9	21.5
3 Western Rocky Mtns.	43.6	5.8	37.8	86.7
4 Eastern Rocky Mtns.	52.4	23.9	28.5	54.3
5 West Texas Area	151.6	106.4	45.2	29.8
6 Western Gulf Coast Basin	109.0	79.7	29.3	26.9
7 Midcontinent	63.0	58.4	4.6	7.3
8-10 Michigan, Eastern Interior and Appalachians	36.5	30.5	6.0	16.4
11 Atlantic Coast	3.8	0.2	3.6	94.7
Total	561.8	384.9	176.9	31.5
Offshore and South Alaska				
1 South Alaska including offshore	26.0	2.9	23.1	88.8
2A Pacific Ocean	49.6	1.9	47.7	96.2
6A Gulf of Mexico	38.6	11.5	27.1	70.0
11A Atlantic Ocean	14.4	0.0	14.4	100.0
Total	128.6	16.3	112.3	87.3
Total US (ex. North Slope)	690.4	401.2	289.2	41.9
Alaskan North Slope				
Onshore	72.1	24.0	48.1	66.7
Offshore	47.9	0.0	47.9	100.0
Total	120.0	24.0	96.0	80.0
Total US	810.4	425.2	385.2	47.5

* See Figure IIA3.4

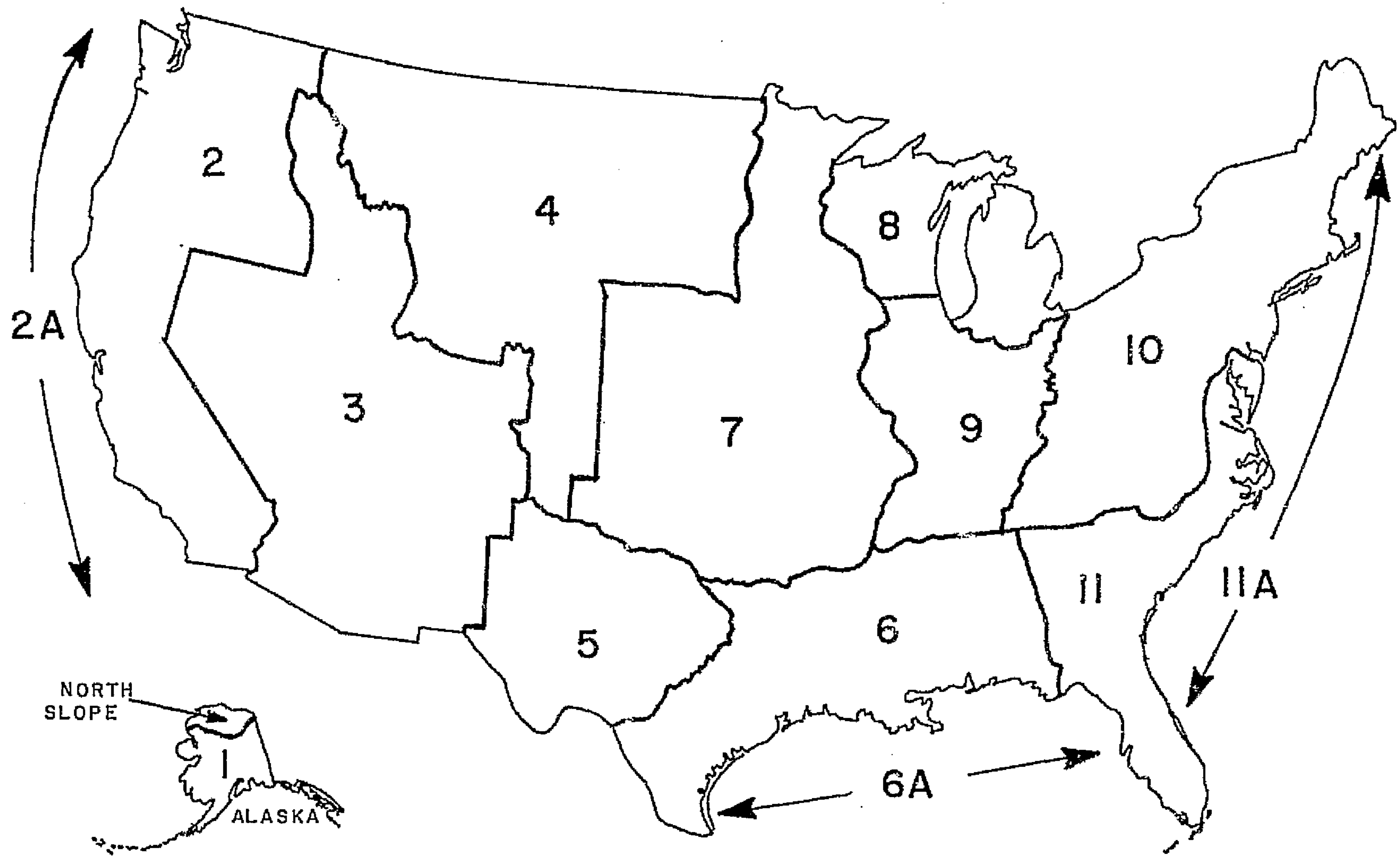

Figure II A 3.4

Petroleum Regions in the United States [10]

d. Limitations

Again, environmental concerns about offshore drilling, particularly off the potentially rich East coast, may delay or stop development of certain U. S. reserves [4]. Delaware passed a Coastal Zone Act in 1971 that effectively prohibits refinery construction in that State. Maine's Environmental Improvement Commission has blocked a number of refinery proposals for that State. All of these developments have discouraged oil exploration and production in that area.

In addition, some hopes have been dampened over the possibilities of East Coast offshore bonanzas. In the past 5 years, 65 holes have been drilled off Newfoundland. All but three were dry, and these three had such low flows as to not justify a pipeline to shore [1].

The major short term limitation to oil recovery may be the shortage of drilling and production equipment. Although 1974 well completions are up 20% over 1973 they are estimated to be 25 - 30% short of the planned drilling program [15]. This shortage, caused by sudden increase in drilling in 1974 after several years of constant activity, is expected to be alleviated by the end of 1976.

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4. Shale Oil

Oil from shale is not a new technology. Potential developers of the oil shales of Western Colorado have been waiting since the 1920's for a favorable economic climate. Oil shale was mined in Scotland for about 100 years beginning in 1850. Also about 25 million tons of shale per year are now mined in Estonia.

a. National Reserves and Location

Oil shale is found in many areas of the United States, but almost all the shale that is rich enough to yield more than 15 gallons of oil per ton is located in one geological formation along the Green River in Colorado, Wyoming and Utah, Figure IIA4.1. The United States Department of the Interior controls about 80% of this land. Estimates of the total yield range from one to two trillion barrels of oil [1-5], but almost all the prime shales (30 gallons per ton in seams at least 30 feet thick) are in the Piceance Creek basin in Colorado. These reserves are estimated to be between 75 and 120 billion barrels [1-3]. The total economically recoverable shale oil has been estimated at between 75 and 600 million barrels [1, 3, 5].

Reference 6 lists reserves of between 100 and 1000 Q's of oil shale energy. References 6 and 7 states that the U. S. Geological Survey puts the number at closer to 3500 Q. The National Petroleum Council [1, 8] puts shale oil reserves at 20 billion barrels (116 Q) of 35 gallon per ton shale, over an unbroken area of at least 30 feet depth, 57 billion barrels (330 Q) of 30 gallon per ton shale over an unbroken area of 30 feet depth, 111 billion barrels (644 Q) of 30 gallon per ton shale in broken intervals, and 188 billion barrels (1090 Q) of poorer quality shale.

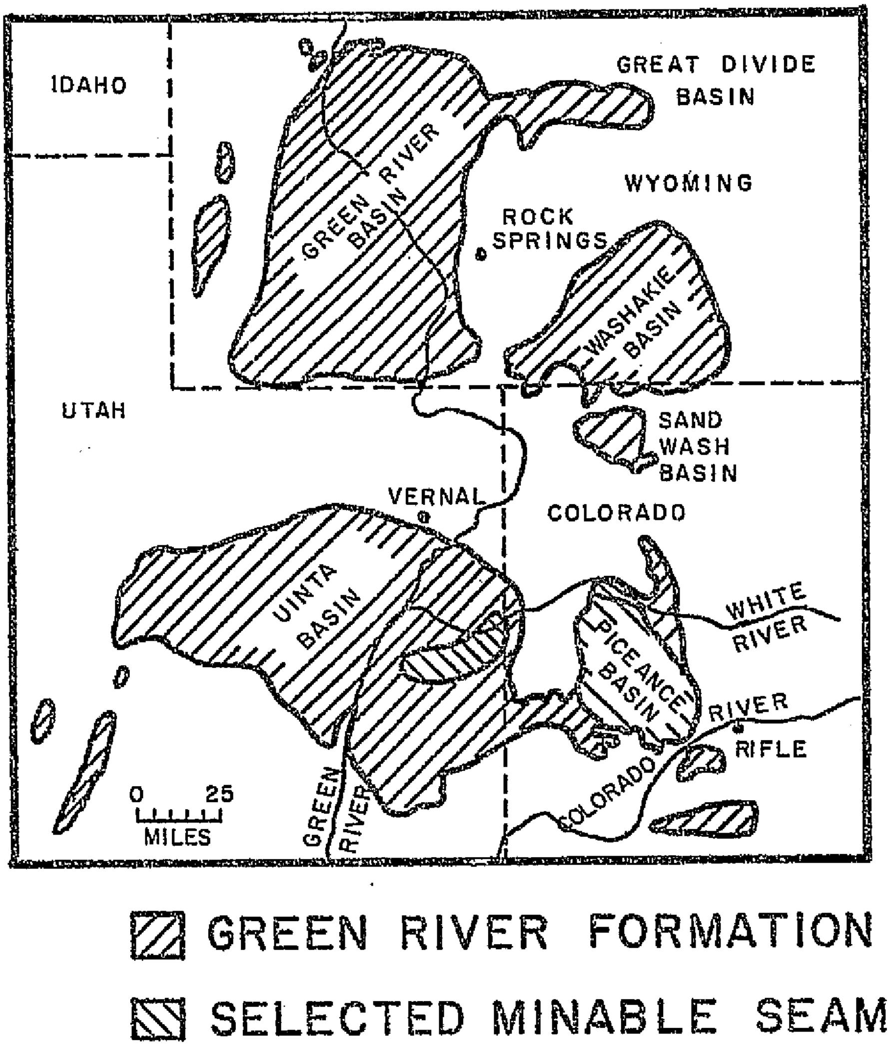

Figure II A4.1

United States' Shale Oil Deposits [10]

Recovery is estimated at about 50 percent by sub-surface mining and at near 100 percent for strip mining. Assuming about 50/50 mining, Merklein [8] estimates total recoverable reserves of 252 billion barrels (1460 Q).

In 1957 the Union Oil Company of California tested a pilot plant that was built along the Parachute Creek, south of the major deposits in the Piceance Creek basin. The Union plant extracted oil from up to 1000 tons of shale a day. It closed in 1958 because the market prices for crude oil were too low to make the operation profitable. Union plans a 50,000 barrel per day plant to be opened in 1979. Colony Development Corporation (Atlantic Richfield, TOSCO, Ashland Oil and Shell Oil) has spent $55-million for research with a pilot plant that has processed 1000 tons of shale per day. Colony has started building a 50,000 barrel per day plant to be completed in 1977. A summary of other activity in the Rockies is given in reference 9.

Some estimate a one million barrels-a-day industry by 1988 [4, 5, 10]; others are less optimistic and predict only 100,000 to 250,000 barrels a day by 1985 [1, 2]. The United States Department of the Interior, which controls the development of the area is presently talking of limiting production to a million barrels a day [2]. Snyder [11] projects production at 250,000 barrels per day (1.45×10^{-3} Q/day) by 1981, increasing to 900,000 (5.2×10^{-3} Q/day) by the mid 1980's, with an ultimate predicted production of 5 million barrels per day (29×10^{-3} Q/day). The limit is caused by the availability of water. The NPC [1] puts 1985 production at between 100,000 and 750,000 barrels per day.

b. Cost

The price of crude from oil shale has been projected to be from as high as $11.50 per barrel to as low as $4 per barrel [1-3, 5]. The Lawrence Livermore Laboratory, University of California, claims synthetic crude could be produced for as little as $2 a barrel [5, 9] using nuclear blasts to open shale rocks and cook out the kerogen. A $1 per barrel price is predicted by Occidental for their hybrid in situ process [4], but most are skeptical. The NPC [1] projects minimum prices of $5.10 to $5.80 for syncrude using high quality shale.

Merklein [8] believes costs comparable to 10 dollars per barrel are perhaps reasonable. This includes the cost of upgrading the shale crude to reduce viscosity and increase pour point to allow pipeline shipment, and the cost of reducing nitrogen content so that existing refinery catalysts can be used without deactivation.

c. Limitations

There are three basic methods for extracting the shale: strip mining, underground mining and in situ processing. These methods are described in references 3-5. The in situ approach shows the most promise but is at least 15 years away [2]. Occidental, as mentioned above, has proposed a hybrid process of underground mining coupled with in situ processing. The predictions are that even this hybrid process is between 6 and 10 years away from commercial production.

Unless a true in situ process can be developed, oil shale use will require a tremendous mining effort. Oil shale has such a low energy content that even high grade deposits yield only 0.6 barrels of crude per ton of shale. Even coal would produce two barrels of synthetic oil

per ton if the technology were available. To support a one million barrel of oil per day industry would require the mining, transporting, crushing, and retorting of 1.5 million tons of oil shale per day, then disposing of 1.3 million tons of residue per day. The volume of this residue may have increased by as much as 50% over the mined volume [5]. This totals to one billion tons handled per year. Last year total coal production in the United States was 570 million tons. Occidental's hybrid process would require about 250 million tons of rocks to be mined and moved each year.

Because of the massive mining requirements and the aridity of the region where shale oil occurs, shale oil development will inevitably alter the environment and has the potential for extensive damage. The problems include: water depletion, disposal of spent shale, revegetation of affected areas, disturbance of natural habitats, increased salinity of the Colorado River, and the release of dust and sulfur dioxide in the air. A true in situ process would eliminate some but not all of the problems. Underground aquifers would leech salts from the spent underground shale and dump the salts and acids into the rivers.

In conventional underground mining of shale three barrels of water are required for every barrel of oil produced. This is about one-third the amount required to gasify or liquefy coal [6, 13]. In situ processes could halve the water requirement. Most spent shale from conventional mining will be disposed of above ground, probably in nearby canyons. There is concern by many that the dry, salty, nitrogen-, phosphorus-poor piles of spent shale will never support vegetation, especially in an arid region (10-15 inches of rain per year). For example, a TOSCO (The

Oil Shale Company) test plot of spent shale with no fertilizers or mulch added took two years before "tiny weeds" appeared. And this was only after over 40 inches of water was applied. A million barrel per day shale oil industry would reduce the quantity of fresh water flowing into the Colorado River enough that the salinity at Hoover Dam would increase by 1.5 percent [2]. Some believe that effect will be dwarfed by the contributio of salt added to the Colorado River from saline aquifiers and leeching of spent shale. It has been estimated that this effect could increase the salinity at Hoover Dam by 50% [2].

Legal barriers to shale development also exist because some 25 percent of the higher grade shale has clouded title because of disputes between private owners and the Interior Department [8].

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5. Tar Sands

a. National Reserves and Location

Little tar sand reserves exist within the borders of the United States. Some 17-28 billion barrels of bitumen in tar sands exist in Utah, with smaller scattered amounts elsewhere. This would produce about 7.5 billion barrels of oil (44 Q) ultimately [1-3].

With an investment of approximately one and one half billion dollars in plant construction a year, the Athabasca oil sands of Canada could be producing about four million barrels a day of unrefined bitumen by 2010 [4]. This peak production could last approximately 20 years. By 2065 production would be cut in half and recoverable reserves exhausted by 2085.

The Athabasca Oil Sands represent about two-thirds of Alberta's oil sand. It is estimated that 900 billion barrels of bitumen [4,.5] lay in three different areas running West-to-East across the middle of Alberta (Fig. IIA5.1). This bitumen refines to about 630 billion barrels of crude oil. Only about one-third of this reserve is judged to be recoverable by present technology -- 30 billion barrels by strip mining and 300 billion barrels by a yet to be developed in situ process [5]. The in situ process is expected to be on line in the mid-1980's. At present only one project (by Great Canadian Oil Sands Ltd.) is operating and is producing 50,000 barrels per day. Two mine projects expected by 1979 will add about 250,000 barrels per day.

b. Cost

The costs of one and one-half billion dollars mentioned above are for plant construction only. The mining, extraction and refining cost

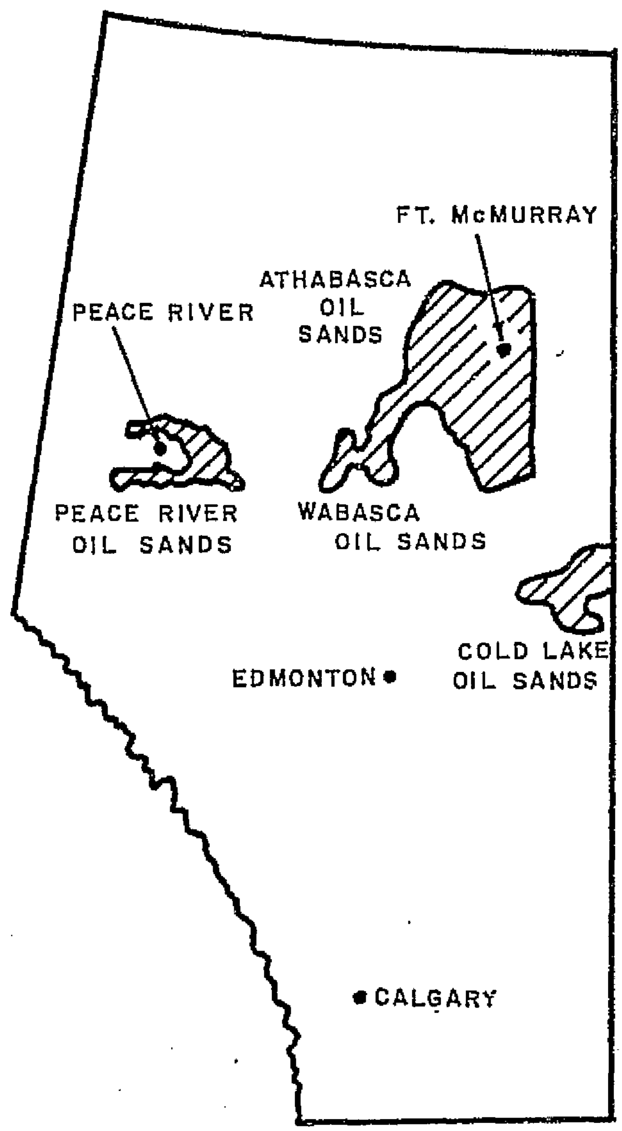

Figure II A 5.1

Canadian Tar Sand Deposits [5]

must be added in. The extraction process alone runs \$4 - \$5 per barrel. Guardian Chemical Corporation claims to have developed a new process which reduces this to \$3 - \$3.50 per barrel [6]. A summary of the total process from land clearing to reclamation is given in reference 7.

c. Limitations

The major problems in developing the tar sands are: lack of trained personnel, lack of adequate financing and the 2000 mile transport of the refined product. In addition, this is Canada's resource and there is certainly no reason to expect a large portion of this fossil fuel to come to the United States. In fact, recent Canadian policy shifts would indicate that little or none will [8-10].

TAR SANDS REFERENCES

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6. Summary

Many methods of projecting resource life are available. All methods require two points: first, the reserves available for production, and second, the rate at which these reserves will be used. As can be seen from the resource predictions of the preceding sections, there is considerable disagreement as to both values for the different fossil fuels. The rate of use has usually been taken as an extrapolation of historical trends. However, no such trends are available for shale oil or tar sands, and any projections of lifetime for these resources are so speculative as to be useless.

For coal, natural gas and petroleum, extrapolation of historic growth is possible but risky because of the large changes in growth conditions that have occurred in the last year. Policy changes aimed at increasing domestic production, shifting to coal where possible, and rapid development of alternatives make it very difficult to project use rates into the future.

With an understanding of these very great uncertainties, some projections can be made. They are uniformly disheartening.

Probably the most well-thought-out study of resource lifetimes based on extrapolation of historical trends is that carried out by Hubbert, the most recent exposition of which is contained in reference 1. Hubbert presents projections of reserve lifetimes, along with an interesting history of estimates of ultimate oil reserves over the last 20 years. Of most interest is Hubbert's treatment of oil, originally made in the 1950's. His projection of expected discoveries, reserve additions, and production have proved remarkably accurate through the present . His prediction of resource lifetime, based on historical

use data, is essential depletion by 2025, with peak production already past. Recent extremely large increases in drilling activity and production may well change such a prediction to make depletion more imminent.

A look based on more recent data is taken from the Project Independence study [2]. In Table IIA6.1 the years left at 1972 consumption rates to consume proven reserves are shown. This is somewhat misleading for two reasons: first, 1972 consumption rates are certainly not representative of future trends, and second, proven reserves are not a good measure of ultimate production. This latter point is particularly true of oil and natural gas, where offshore discoveries will probably increase proven reserves significantly.

The projected number of quads of the U. S. ultimately recoverable reserves (including Alaska) as shown in Sections IIA-1 through IIA-5 (using the method outlined in Section I) and their lifetimes assuming either a no-growth or a 5 percent growth in use are summarized in Table IIA6.2. The 5 percent growth curves are believed most representative based on the belief that, although energy growth has traditionally been between three and five percent per year in nearly all areas, the shift from foreign dependence to domestic supplies will undoubtedly show up as an increased use rate of U. S. reserves in the near future.

Costs of energy where available have been pointed out in each section. It is extremely difficult to project prices of energy, because prices are so dependent upon government policy and fluctuating market conditions. Costs of energy production can be of importance as pointed out in Section IIA-3 for petroleum. Comparative costs for various

TABLE IIA6.1
Proven Reserves [2]

Source	Fuel Units	Quadrillion Btu's	Years Left at 1972 Consumption Levels
Coal			
high sulfur (more than 1%)	273 billion tons	6908	
low sulfur (less than 1%)	160 billion tons	3838	
TOTAL	433 billion tons	10746	823
Oil			
Lower 48 (crude)	30 billion barrels	176	
natural gas liquids	6 billion barrels	37	
Alaska	10 billion barrels	59	
TOTAL	46 billion barrels	272	8
Gas			
Lower 48	218 TCF	225	
Alaska	32 TCF	32	
TOTAL	250 TCF	257	11
Shale	20-170 billion barrels	116-986	3-28
Tar Sands	29 billion barrels	168	28

TABLE IIA6.2

Summary of US Fossil Resources and Life Expectancy

Resource	Recoverable Reserves (1972) Q		Production per year (1972) Q	Year of Depletion, Growth rate, b, percent: 0 (1972 use rate)		2		5	
	min	max		min	max	min	max	min	max
Coal	3900*	7000*	12.4	2268	2540	2071	2100	2028	2040
Natural Gas	450	2000	22.1	1992	2062	1989	2022	1985	2006
Petroleum	496	2320	22.4	1994	2075	1990	2029	1987	2008
Shale Oil	100	3500	negligible	NOT PREDICTABLE DUE TO PRESENT LOW PRODUCTION AND STATUS OF TECHNOLOGY					
Tar Sands	44	168	~0						

*Recoverable at present prices.

energy forms, including costs of environmental protection, are given by Table IIA6.3 from reference 3.

Fossil fuel resources are so heavily in demand, regardless of reserve predictions and lifetimes assumed, that it appears doubtful if much can be committed to the large scale production of hydrogen. Future prices of energy will probably rise drastically due both to the shortage of energy and the shortage of capital necessary for the expansion needed. These same factors will cause the price of hydrogen to increase greatly over present predicted costs. It is impossible at this time to project relative fuel prices as much as a few years into the future, let alone to the longer term when a hydrogen system could be in operation.

TABLE IIA6.3

Costs of Energy [3]

I. Electric Power	Capital cost ($/kW)	Fuel, Operations and Maintenance Cost (mill/kWh)	Total Cost (mill/kWh)
1. Nuclear fission	450	2·0	11·0
2. Nuclear breeder	565+	1·0	12·2
3. Fossil plants	230	6·0	10·6
4. Combined cycle turbines	115	6·0-10·0	8·3-12·3
5. Solar power heat engine	1000?	1·0	14·8
6. Cost to consumer			30·0

II. Fuel	mill/kWh (fuel)
1. Coal	1·6
2. Gas	1·54
3. Gas from coal	2·75
4. LNG from Algeria	3·2
5. Wellhead oil (domestic)	1·83
6. Gasoline at refinery	3·4
7. Gasoline at gas station	9·5
8. Fuel oil to customer	4·55
9. Gas to customer	4·80

III. Costs of Environmental improvement	(mill/kWh)	Percentage of generation cost	Percentage of consumer cost
1. Cooling tower (wet)	0·6	5·45	2·0
(dry)	1·47	13·4	4·9
2. Reclamation of strip-mined land	0·5	4·7	1·67
3. SO_2 control	2·1	19·7	7·0

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B. NON-DEPLETABLE RESOURCES

1. Projected Water Resources

Water resource availability is an extremely serious problem for the development of energy resources within the lower 48 states. As the Project Independence Report states [1]:

> Water is essential to almost every energy process. It is needed to extract raw materials from the earth, process the materials to a useful fuel, generate energy from these fuels and dispose of waste products in an environmentally acceptable manner. Water is also used for hydroelectric power generation and for transportation of fuels and materials. Water requirements vary depending on the source of energy, region of development, and extent of environmental control.

The dependence of various energy forms on water availability is demonstrated in Table IIB1.1, summarized from references 1 and 2.

Projected use patterns according to Project Independence show that water supply will be adequate in the East, the Pacific Northwest, Alaska, Hawaii and Puerto Rico, with potential problems in the North Atlantic and Ohio regions, and serious problems in the Missouri and Upper Colorado River Basins. In the Ohio region, 49 percent of water use already goes to energy production.

The strip mining areas of the Western states have particularly severe problems [1, 3]. According to a National Academy of Sciences panel as reported in reference 3, Montana's share of water in the Yellowstone basin is already "completely committed, perhaps overcommitted," Wyoming's allotment is almost completely spoken for, and water from the Colorado basin is overcommitted to the point that tributary states' expectations exceed the supply. Most of these commitments are to oil and coal mining companies, and to power generation stations to be constructed in the strip mining areas. Strong

TABLE IIB1.1
Water Used for Energy

Energy Source	Standard Unit	Consumption Demand For Water	Water Needed Gal/10^6 BTU	Major Uses of Water
Western coal mining	ton	6-14.7 gal/ton	0.25-0.61[1]	Dust Control Coal Washing
Eastern surface mining	ton	15.8-18.0 gal/ton	0.66-0.75[1]	Dust Control Coal Washing
Eastern subsurface mining	ton			Dust Control Coal Washing
Oil shale	barrel	145.4 gal/bbl	30.1[1] 19-29[2]	Mining, cooling, oil shale disposal, preparation
Coal gasification	MSCF	72-158 gal/MSCF	72-158[1] 37-158[2]	Process use Cooking use
Coal gasification	barrel	175-1,134 gal/bbl	31-200[1,2]	Process use Cooking use
Nuclear	kwh	0.80 gal/Kwh	23[1,2]	Cooling, uranium mining
Nuclear fuel processing			14[2]	Processing, including electrical consumption
Oil and gas production	barrel	17.3 gal	3.05[1]	Well drilling, secondary and tertiary recovery
Refineries	barrel	43 gal/bbl	7.58[1] 7[2]	Process H_2O Cooling H_2O
Fossil fuel power plants	Kwh	0.41 gal/Kwh	120[1] 146[2]	Cooling H_2O
Geothermal power plants	Kwh	1.80 gal/Kwh	527[2]	Cooling H_2O
Gas processing plants	MSCF	1.67 gal/MSCF	1.67[2]	Cooling H_2O

1 "Water for Energy" report of Arthur D. Little, Inc. to the Federal Energy Administration, 9/5/74.

2 Davis, George H. and Wood, Leonard A. U. S. Geological Survey Report, 1974.

environmental objections to these arrangements are being mounted. The overlay of these regions with coal and oil shale reserves is demonstrated in Figure IIB1.1 from reference 1.

The Texas-Gulf, Rio Grande, Great Basin and California regions also have short fresh water supplies and thus possible energy production problems especially after 1985. (Table IIB1.2, ref. 1)

Reference 4 reports a fairly detailed study of water use forecasting methods and their results, giving water use predictions for various regions of the country through the year 2020. The report notes the following factors important to a future hydrogen system:

1) Water use is very largely determined by policy and regulation at the Federal level.

2) The cost of water rapidly increases as the level of developed flow approaches maximum regulation. (The Colorado and Rio Grande basins are already fully regulated.)

3) Augmentation of natural runoff is possible, but quite expensive and in some cases environmentally unacceptable.

4) Withdrawal of water from watersheds is chiefly for agriculture, but cooling of steam-electric generating plants is second, accounting for 25 percent of withdrawals.

5) If once-through cooling and present power plant efficiencies are maintained, projected electric power plant water requirements alone will require water withdrawals of the same order as the average annual runoff of the contiguous United States by 2000. Consumption (via evaporation) is about one percent of withdrawals.

6) Water use by electrical production is tied strongly to the rate of economic growth. Water use may be 65 percent of the high projections if the economy grows more slowly.

7) Higher water costs will reduce once-through cooling and thus withdrawal rates.

Figures IIB1.2 and IIB1.3 from reference 4 shows projected relative uses of water in the United States under three projections, an extreme

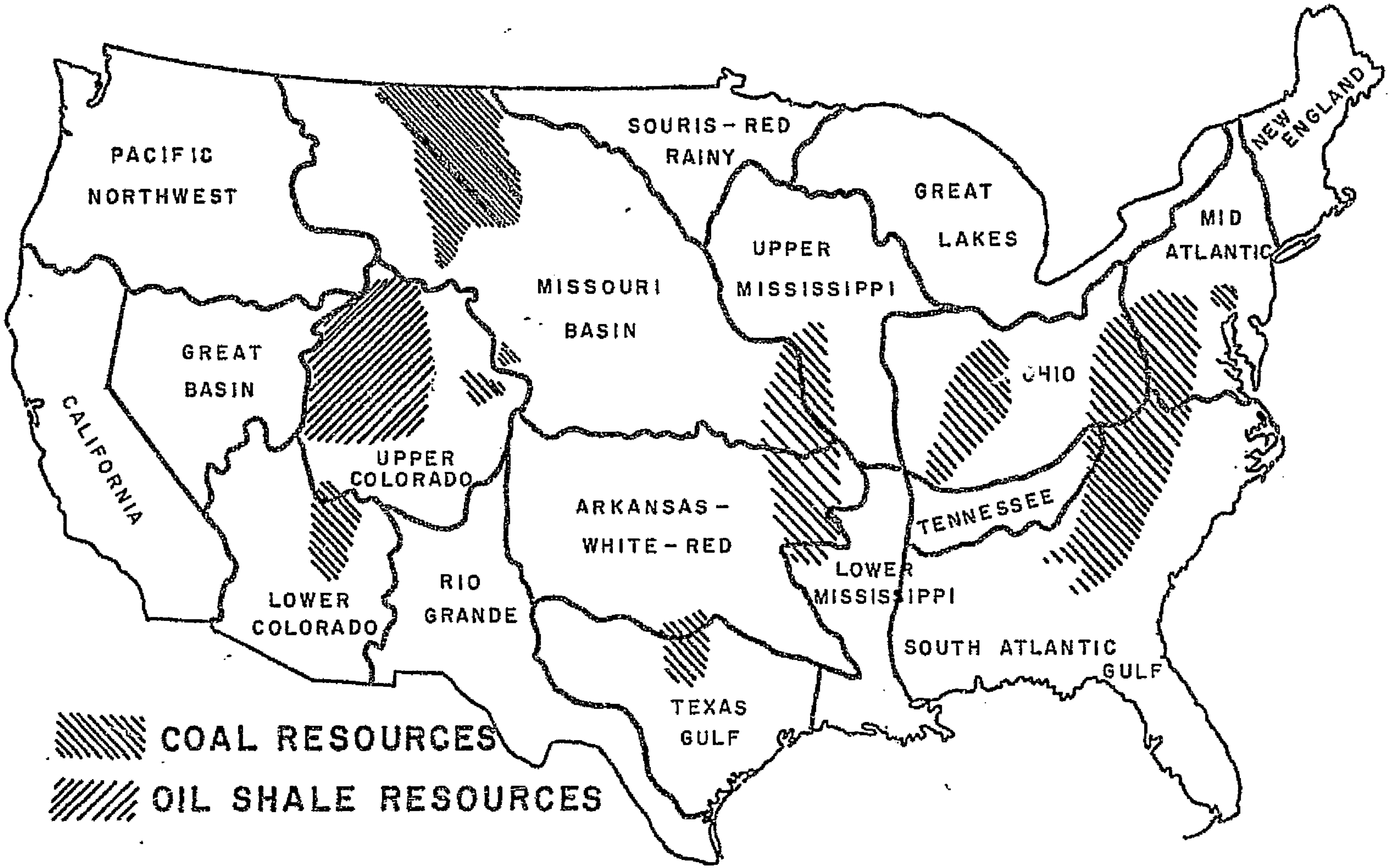

Figure II BI.I

Water Resource Regions with Coal and Oil Shale Resources [1]

TABLE IIB1.2

Critical Water Regions [1]

Millions of Acre Feet Per Year

	Surface Water Supplies(1) (runoff)	Groundwater and Marine/Estuary Supplies (current use - 1970)	Total Water Supplies (Ground & Surface)	Total Consumptive Use as a Percent of Total Water Supplies - 1985	Energy Related Comsumptive Use as a Percent of Total Consumptive Use 1985
Upper Colorado	11.2[2] (6.3)	.1	11.3 (6.4)	79.7	8.4
Lower Colorado	1.9[3] (8.5)	5.0	6.9 (13.5)	34.1	1.1
Great Basin	2.8	4.6	7.4	51.4	1.4
Rio Grande	3.0	2.9	5.9	96.6	6.7
Missouri Basin	37.0	6.8	43.8	35.4	2.4

(1) The fresh surface water supplies used herein represent that amount of water originating from each region for (1) 50 percent of the total surface storage which existed as of January 1963 and (2) for a degree of certainty which can be assured 98 out of every 100 years. This material was derived from a paper prepared by the United States Geological Survey.

(2) The Colorado River Compact of 1922 required delivery of 75 million acre-feet of water in any 10-year period from the Upper Colorado River Basin to the Lower Colorado River Basin. Estimates of the water remaining for consumptive use in the Upper Basin range from 5.8 to 6.3 million acre-feet per year, depending upon assumptions used in interpretation of the Compact.

(3) The water available annually for consumptive use in the Lower Basin is increased by the amount released from the Upper Basin less 1.5 million acre-feet required to satisfy the U. S. - Mexico treaty obligations. This amount depends upon interpretations of the Colorado River Compact, could be as high as 8.5 million acre-feet per year.

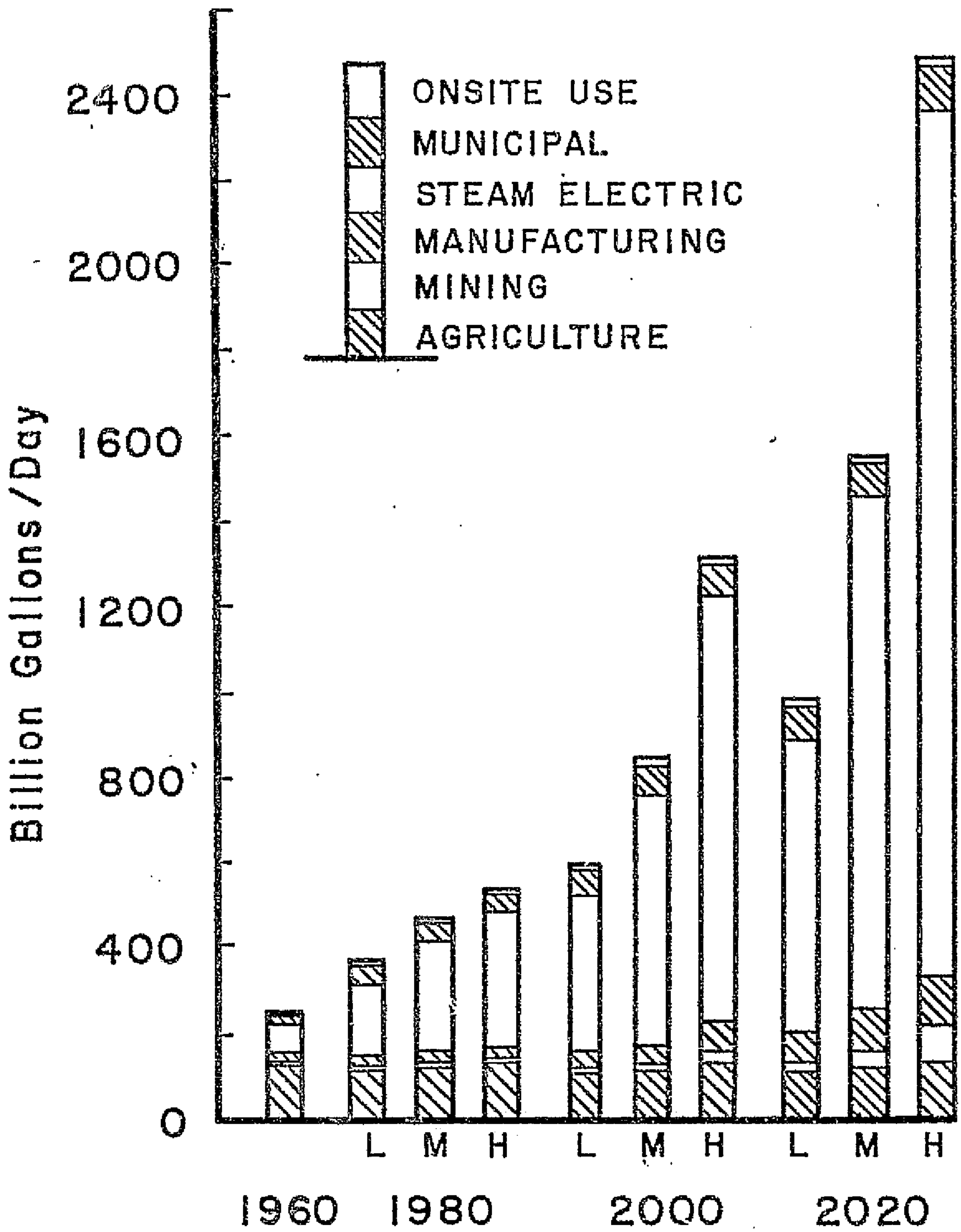

Figure II B1.2

Present and Projected Water Withdrawals for the United States [4]

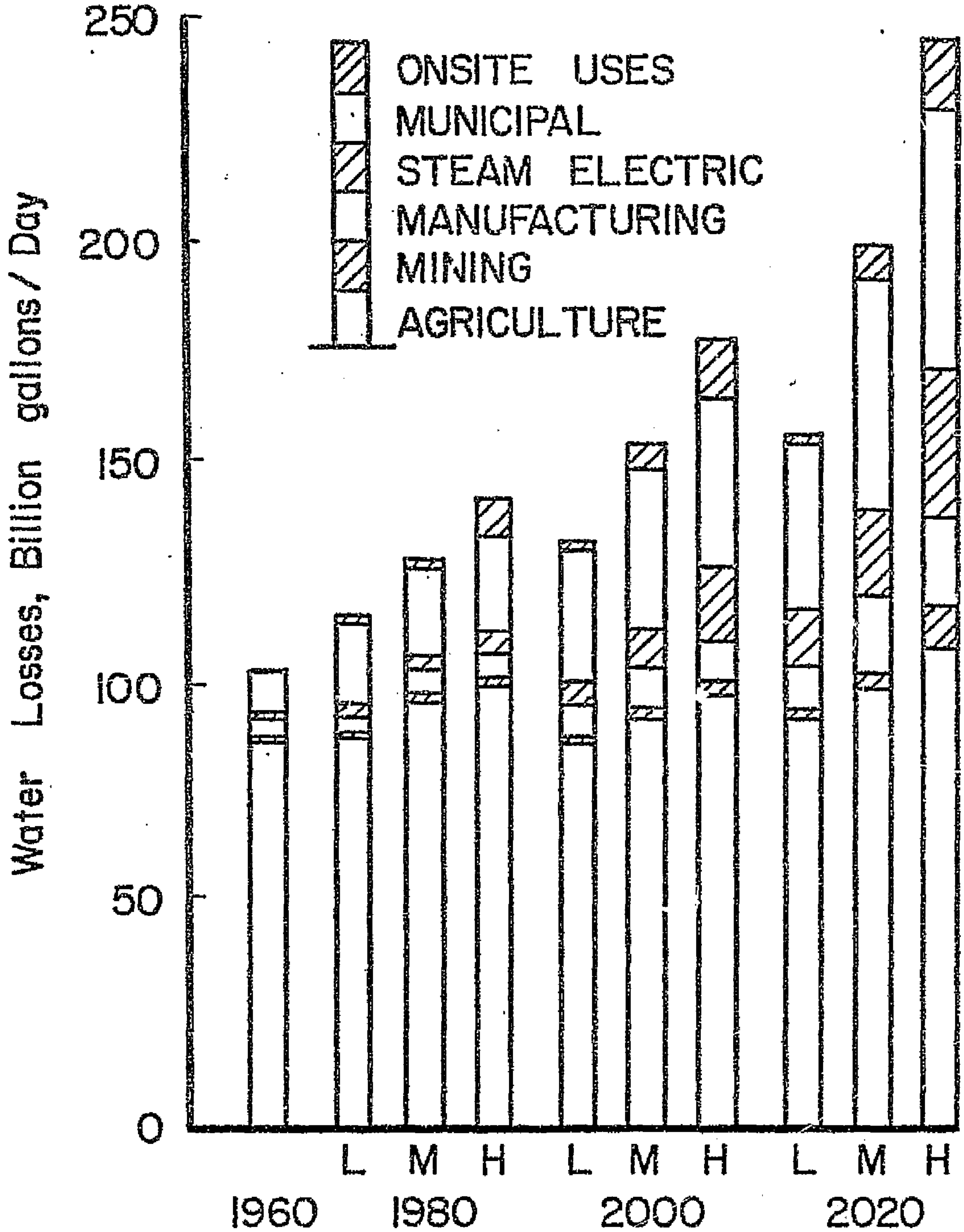

Figure II B1.3

Present and Projected Water Losses for the United States

low, best estimate, and extreme high. Note that these projections, done in 1971, do not include any allowance for coal gasification, slurry pipelining, hydrogen production or other synthetic-fuel related processes. They are in that sense optimistic.

References 5 and 6 are attempts to forecast water use for agriculture under various assumptions as to future policy. Agriculture contributes about 85 percent of present water consumption (as opposed to withdrawal) in the United States. Their forecasts show that sufficient water is available, with local exceptions, to produce the food and fiber requirements of this country through 2000. Again, it must be noted that these studies did not include the effects of the increased water needs that are envisioned for a major shift to coal or oil shale use for synthetic fuels, nor was the effect of the developing world food crisis used in the analysis.

Conservation -- use of dry air cooling and cooling lakes can reduce withdrawal for electrical generation [7]. Other conservation measures for industry have also been proposed and are being implemented [8, 9, 10]. Conservation for aesthetic and ecological considerations continues to be debated [11, 3]. All of the demands on our water supply can only lead to increasing costs for a previously readily available commodity [12].

On a different aspect of conservation a recent study [13] shows that insufficient water will be available for over 40 percent of the strip mineable coal areas of the West to allow reclamation of the mined areas.

2. Financing

A serious problem is forecast in capital procurement to finance the many rapid expansions needed in all sectors of the energy economy. Winger [14] examines some of the critical areas. He notes that to double the drilling effort for oil alone in the 1970-1985 period would take some $140 billion for drilling and related efforts. He finds no likelihood that the industry can finance such an effort. The National Petroleum Council projects total energy capital requirements for the 1971-1985 period as $451 to $547 billion. This is about double the maximum yearly rate to date. Table IIB2.1 summarizes capital requirements for some projected energy expansions.

TABLE IIB2.1

Summarized Capital Requirements
for Energy Expansion from Part II-A

Total U.S. Capital and Exploration Expenditures Crude Oil, Natural Gas, Pipe Lines, Tankers, Refineries, Chemical Plants, Marketing, Geological and Leasing Expenses 1970-85 [16] (pre-energy crises projection)	$220 billion
Tripling of Coal Production	$ 30 billion
190 new Fossil fuel power plants by 1985	$ 60 billion
170 nuclear plants by 1985	$110 billion
26 coal gasification plants by 1985	$ 20 billion
Arctic - US natural gas pipeline	$ 10 billion
Development of nuclear stimulation and hydraulic fracture for natural gas	$3-10 billion
Doubling of Oil Exploration to 1985 over 1970 projections	$140 billion

3. Manpower

A further necessary resource in completing a shift in our energy base is technical manpower. Very little opportunity exists to shift manpower, because the existing energy system will continue to expand in manpower needs. Thus, new technologies will require new manpower. Reference 15 is an overall look at the manpower situation, with the following prognosis:

1) Acute shortage of engineers at all levels. (Fig. IIB3.1)

2) Special shortages in the near-term of engineers and technicians used in exploration -- geologists, geophysicists and electrical and instrument engineers.

3) Special shortages in the mid-term of mining, chemical and metallurgical engineers.

Other shortages can be foreseen in non-technical and semi-skilled areas. An increase in the number of workers in mining, drilling and processing will be required.

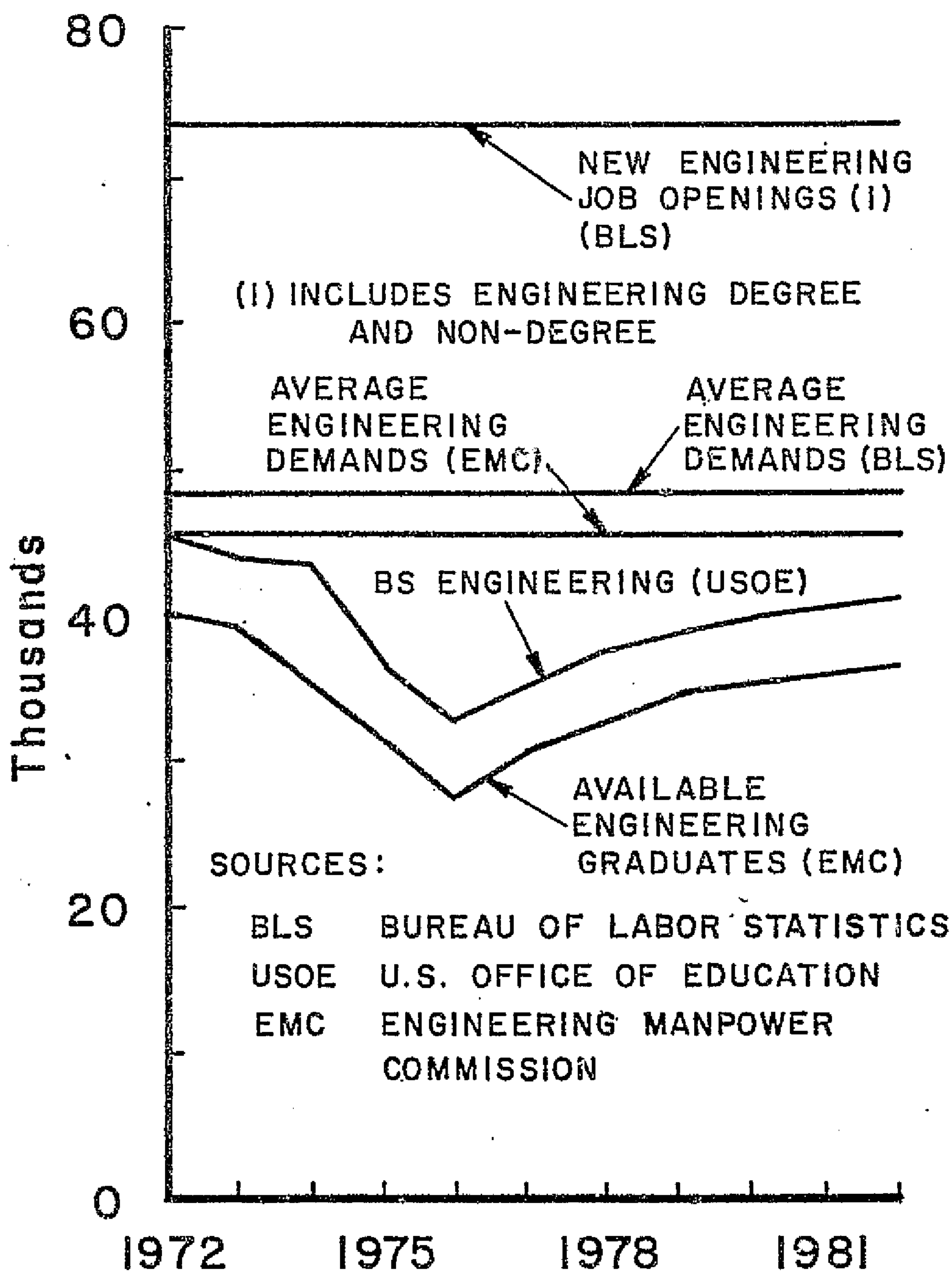

Figure II B 3.1

Projections of Engineering Manpower Needs [15]

4. Summary

Water will become an increasingly scarce and therefore expensive commodity in many energy-consuming and producing areas of the United States, especially after 1985. Hydrogen has significant advantages over other energy systems such as shale oil or coal gasification, in such a water-poor national scene, since hydrogen production centers can generally be sited where water is available. However, certain large scale hydrogen production methods, such as solar energy conversion or production from coal, may well be severely handicapped by water scarcity at the production point. Only a careful study of the tradeoffs of water use for food production, drinking water, energy production, conservation and ecology, and the other major water uses can project the future supply of water in this country. Such a study has not been carried out accounting for the rapid and significant changes of national need and priority of the last few years.

Capital requirements are so huge that high interest rates and short capital supply may be prohibitive in allowing development of all forms of energy. This could significantly retard implementation of a large scale hydrogen energy system, especially by the private sector.

Manpower, particularly those with engineering skills, will be needed in quantities that cannot be met by present or projected engineering graduates.

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III. TRANSMISSION AND DISTRIBUTION OF ENERGY BY HYDROGEN AND OTHER ENERGY CARRIERS

As is presently the case, many forms of transport will probably make up the future energy distribution system in the United States. Local cost conditions, legal and regulatory requirements, form of energy available, terrain, ecological awareness and many other factors will determine the mix of distribution types in any area.

Because of the low density of hydrogen in the gaseous state, shipment by railroad car or other surface transport means including barges, airships [1], trucks, etc. is not cost-effective [2]. In some cases these means are reasonable for liquid hydrogen. However, unless the end use requires the liquid form, the cost of liquefaction to ease transport requirements is not economically sound, since liquefaction costs for hydrogen equal or exceed production costs.

In the remainder of Section III, the major means of energy transmission are examined, and costs relative to hydrogen are given where available.

A. GAS PIPELINES

Reynolds and Slager [3], Beghi et al [4], the 1973 JSC/Houston/Rice NASA/ASEE Design Program [2] and others have examined the cost of transporting hydrogen by pipeline relative to natural gas and, in [2] to electricity by above and underground lines.

Reference 3 concludes on the basis of a careful cost analysis that for an optimized pipeline system carrying gaseous hydrogen, pipelining costs will be about 1.4 times the pipelining cost for natural gas. Some interesting comments and insights from [3] are:

1) The transportation costs of hydrogen can be taken into account in manufacturing site selection and overall system optimization.

2) As time passes, transportation distances and terrain difficulty must increase for natural gas. The Alaskan field and imported LNG are good examples of this trend.

3) Natural gas transportation costs must also include the effect of smaller gathering lines in the fields which are more expensive so that the increased costs given for hydrogen may not be as great as indicated.

4) Natural gas lines are also more likely to be designed or operated off-optimum because of uncertainty in the productivity of a particular producing area. This too would tend to increase costs.

Reynolds and Slager conclude that a factor of only 1.4, when coupled with the additional non-quantifiable factors shown, makes hydrogen closely competitive with natural gas in transportation costs by pipelining. Further, they find that any refrigerated or liquefied hydrogen pipelining method costs more for temperature reduction than can be made up by the reduced costs of pumping. This conclusion was reached without even considering any increase in pipe cost for added insulation capability.

The NASA/ASEE Hydrogen Study [2] examined transportation of hydrogen by pipelining in both existing and specially designed hydrogen lines. They concluded that the pipelining of gaseous hydrogen is without question the lowest cost method of transmitting large amounts. Any system requiring liquefaction of hydrogen, even on the basis of incremental costs for increasing capacity of an existing liquefaction plant, cannot come close to competing with gaseous transmission.

Glover and Roth [5] detail the experiences of a pipeline system in the Houston area that includes lines for providing high purity hydrogen and carbon monoxide to area process plants. No serious technical problems have been found in the seven years of operation of this pipeline. At higher pipeline pressures and purities, there is some possibility that embrittlement of pipe or compressor components may occur. This possibility is discussed at some length in reference 2.

B. CLOSED-LOOP ENERGY PIPES

These pipes operate by adding energy at one end to cause an endothermic chemical reaction, usually at high temperatures. One example is methane/water which, at a temperature of about 850°C yields carbon monoxide and hydrogen by the reaction:

$$CH_4 + H_2O \underset{\text{Ni catalyst}}{\rightleftharpoons} 3H_2 + CO$$

At lower temperature, the reaction can be reversed exothermically using a catalyst, giving up heat at about 450°C [6-8].

In operation, the energy pipes use a high temperature heat source such as a nuclear reactor or solar tower at one end, and the energy is removed at the demand end. Pumping is done by removing a portion of the high energy fluid at a pumping station, using it to power the pumps, and putting the low-energy products into the return pipe. The energy pipe is thus a completely closed energy transfer system. In some systems, the water is not recycled. The advantages are:

1) Use of any high temperature source -- nuclear, fossil, solar, etc.

2) Closed system, no pollutants.

3) System can be optimized for temperature available and reaction system to carry high energy gas.

4) Storage of energy in the gas using underground storage or depleted wells is possible.

Disadvantages:

1) A double pipeline is required.

2) Double pumping costs and losses are incurred.

If thermochemical or thermal decomposition methods for hydrogen production can be made feasible, then all of the above advantages also

accrue to hydrogen, and because nature recycles the raw material, and no return pipeline is therefore required, the two disadvantages do not occur for hydrogen.

C. SLURRY PIPELINES

In 1957, Consolidation Coal Co. initiated operation of a 108 mile pipeline for transporting a coal/water slurry from southeastern Ohio to Cleveland. At that time, savings in transport charges were about one dollar a ton over rail rates. Consolidation had plans to greatly expand this system. In 1963, the pipeline was abandoned, and no further operations were begun. The reason was simply that the railroads developed the unit train, and reduced transportation costs below those of pipeline operation [9 p. 228].

Peabody Coal Co. presently operates a 275 mile 50/50 by weight coal/water pipeline. This is an 18-inch line running through Nevada and Arizona. The coal slurry takes 2.8 days to make the trip.

The technical feasibility of slurry pipelines is obviously well established. Where the railroads have established routes and are willing to use unit trains, they can apparently compete with these pipelines. Local conditions of terrain, trackage and rate of consumption will dictate the choice of pipeline or rail transportation. Possible environmental regulations could make slurry pipelines even more competitive in the future, since they are relatively unobtrusive. Considerable water must be available for large-scale transmission.

At the present time the only feasible rights-of-way for coal slurry pipelines are use at the railroads' rights-of-way. This will remain until Congress grants the right of eminent domain to the coal pipelines.

D. ELECTRICAL TRANSMISSION

Modern overhead lines operating at 750 to 1500 kilovolts may make long distance electrical transmission economically competitive with other modes; however, there is growing concern over the effects of these lines upon people who work or live near them. Russia has already established time-of-exposure standards for workers exposed to 500 kilovolt or greater lines or substations [10].

E. CRYOGENIC CABLES

Cryocables use cryogenic fluids to reduce the electrical resistance of conductors and thus to reduce energy losses in a long electrical transmission line.

Fox and Bernstein [11] have examined system costs for cryogenic cables using various refrigerants, conductors and current capacities. Minimum costs for LN_2 coolant systems ran about $900 per Mw-single-circuit mile, for a 3500 Mw system. Substituting LH_2 reduces the cost to about $800 per Mw-single-circuit mile for a system of similar size.

By combining the pipelining of LNG, liquid hydrogen or other cryogenic fuel with the cable, energy can be transferred by both media. However, the NASA/ASEE Study [2] points out that three requirements must be met before liquid hydrogen can compete with a cryocable or electrical transmission line that does not include cryogenic transmission:

1) The electrical transmission line must have a requirement for underground placement.

2) The transmission line must be long enough so that significant energy losses occur if the line is not cooled.

3) Gaseous hydrogen is available at one end of the line, and liquid hydrogen is <u>required</u> at the other end.

If gaseous hydrogen is needed at the use end of the pipe, it is probably cheaper to build a gas pipeline next to a nitrogen-cooled cable because of the high liquefaction cost of hydrogen.

Whitelaw [12] in a more recent analysis, finds that a liquid-hydrogen-cooled underground cable transmitting hydrogen and designed using new materials technology will transmit more energy per dollar

per mile than separate systems of underground electrical cable and liquid hydrogen pipeline. This is probably so, but neglects the question of who pays the burden of liquefaction costs for hydrogen.

It has been suggested that the liquefaction costs be recovered by using the heat of vaporization of the liquid hydrogen to provide air conditioning or other cooling duty at the use point. However, even projected liquefaction systems work at about one-third of theoretical efficiency; that is, it takes about three times as much energy to liquefy hydrogen (practically) as can be removed using the heat of vaporization. Thus, use of liquid hydrogen for cooling is much less efficient than many other cooling schemes.

C-2

F. COMPARISON OF ENERGY TRANSPORT COSTS

Leeth [8] has compared energy transmission costs among various methods (pipeline, high voltage electrical, etc.) and among various media in pipelines. The results of that analysis are shown in Figures IIIF.1 and IIIF.2. In these curves, the EVA-ADAM system is the methane-water energy pipe, H_2O is hot water at 300°F and 120 psi, and the hydrogen is from thermochemical decomposition. Heat for all non-fossil energy forms is assumed to be nuclear. These comparisons show that fossil fuels provide the cheapest energy transport costs, followed by hydrogen, EVA-ADAM, high-voltage overhead electrical, hot water nuclear heat, and high-voltage underground transmission.

Because hydrogen production and use points can be well defined, the distribution system can be optimized to allow least-cost transmission. Methods for such optimization are outlined by Auriel and Gurovich [3].

In Figures IIIF.3 and IIIF.4 relative costs of energy transmission in various forms are shown from references 14 and 15, respectively.

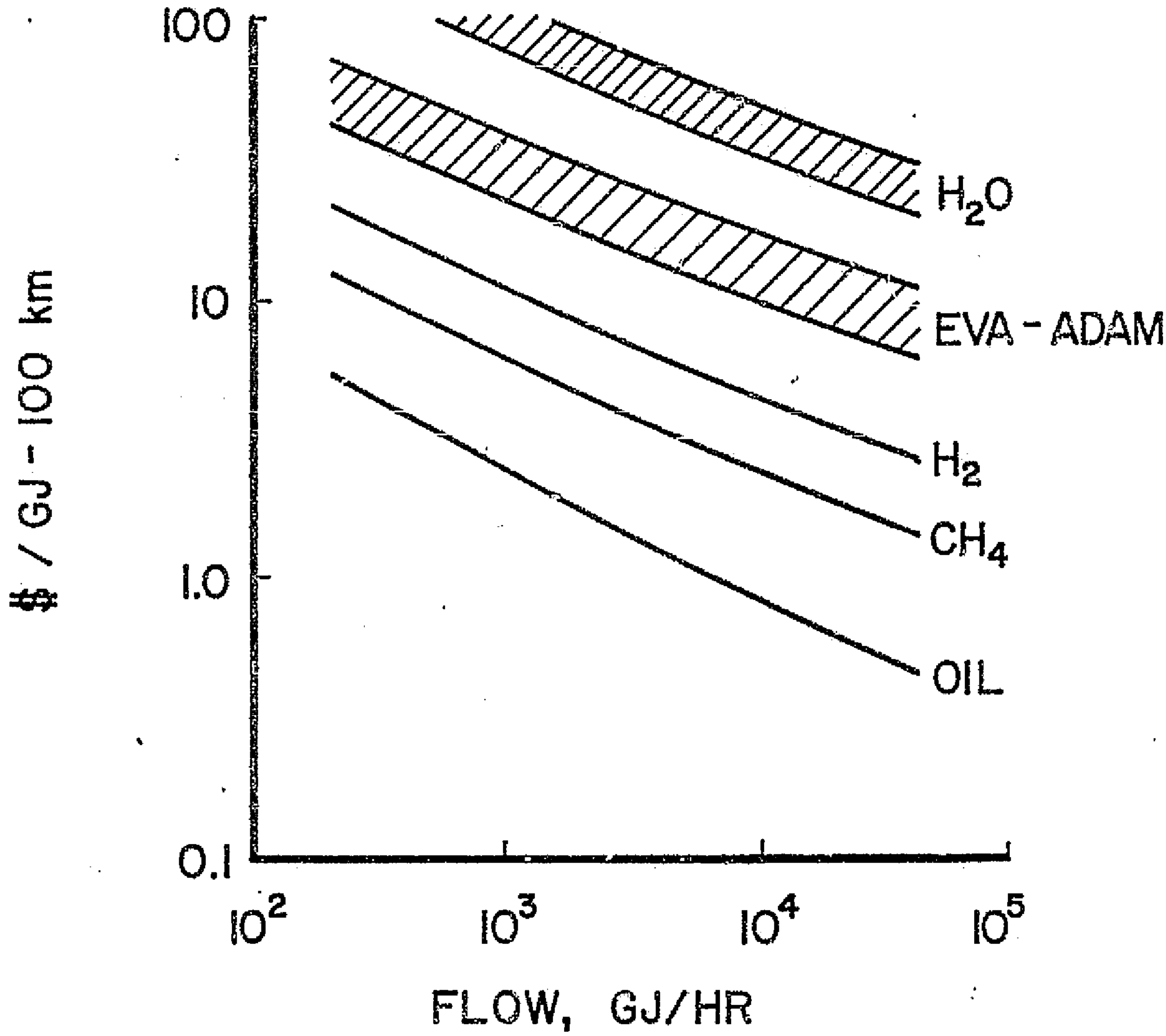

Figure III F.1

Pipeline Transport Costs (1985 Dollars)[8]

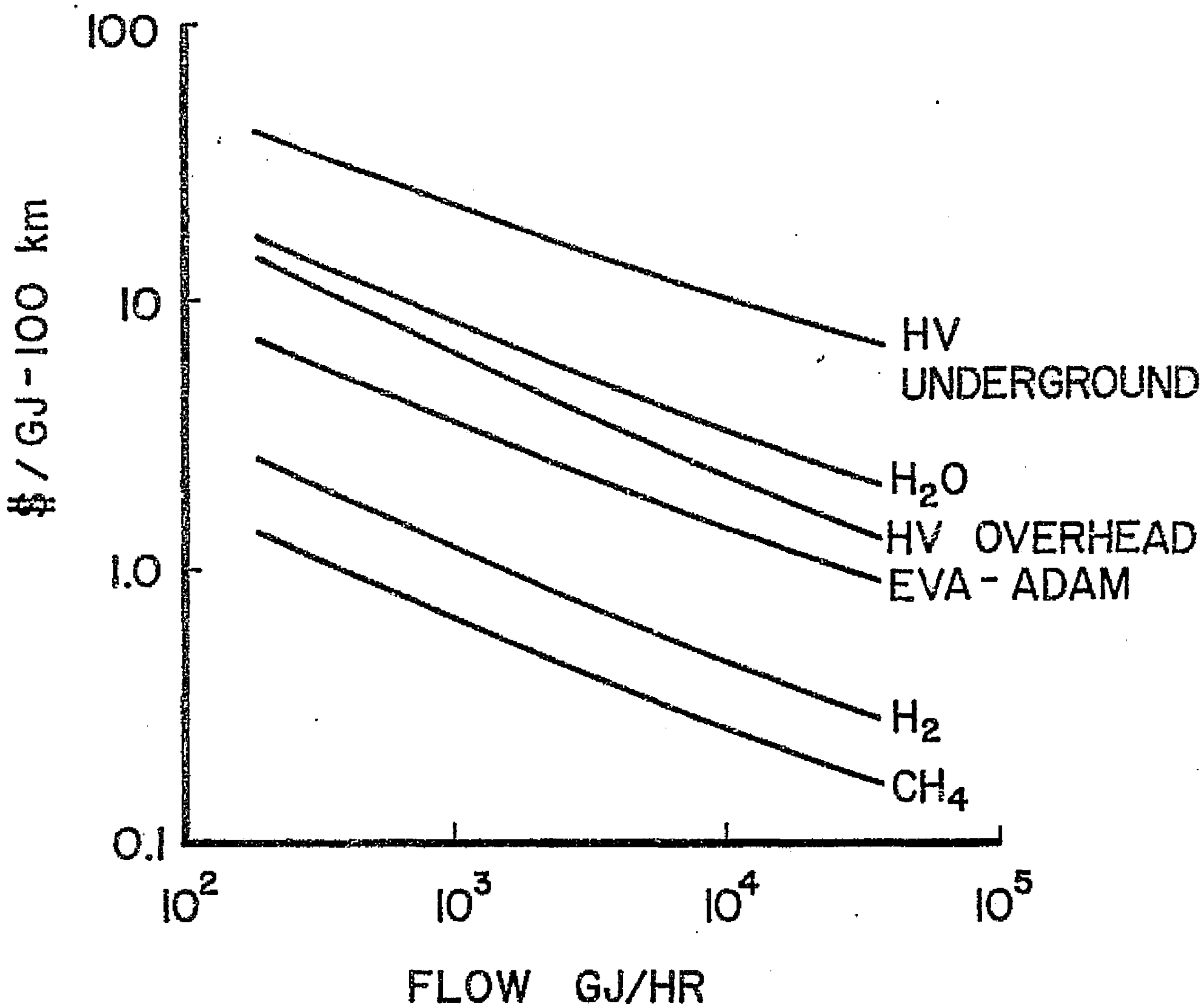

Figure III F.2

Energy Transport Costs (1985 Dollars) [8]

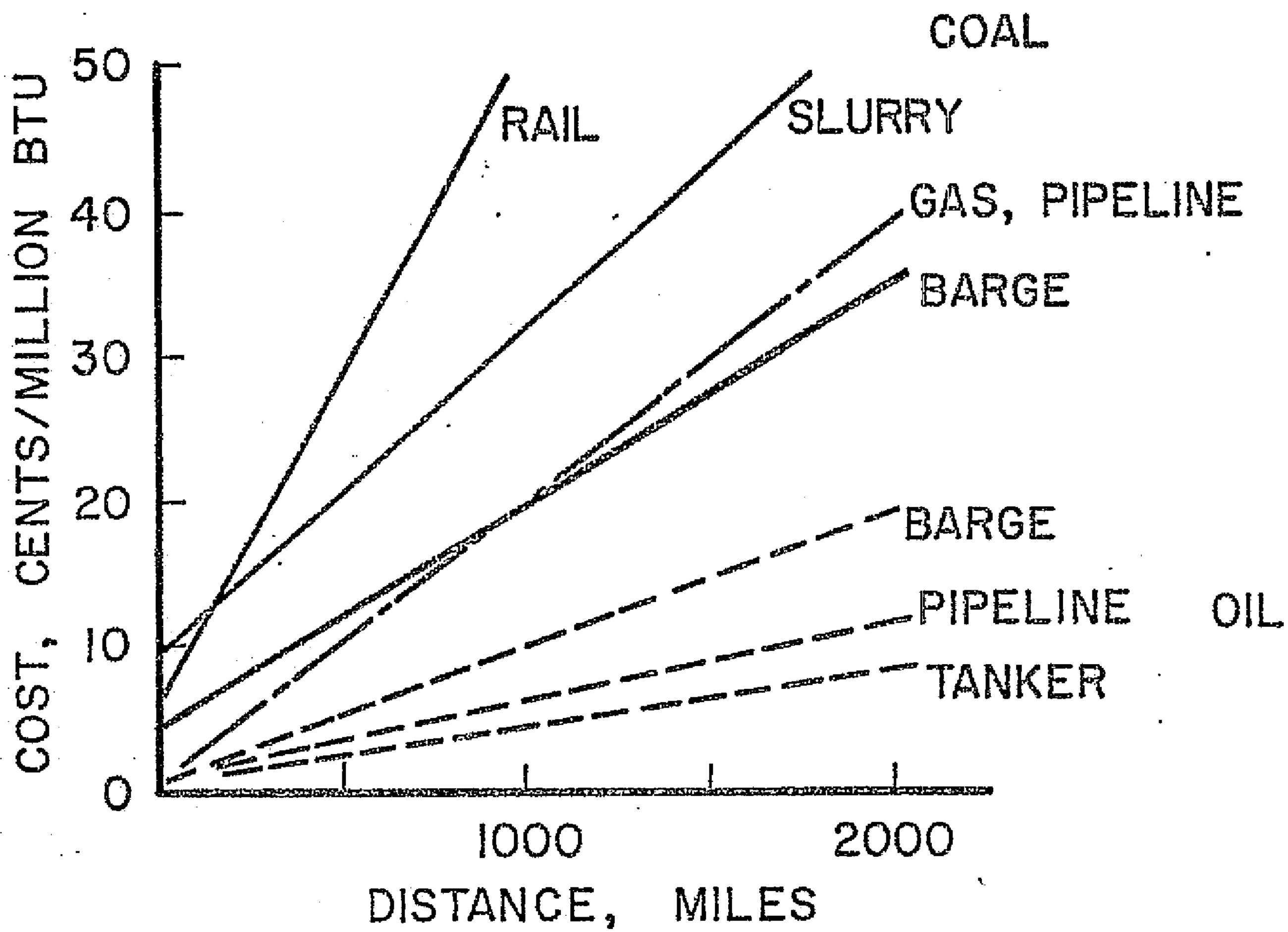

Figure III F.3

Relative Transport Costs for Energy [14]

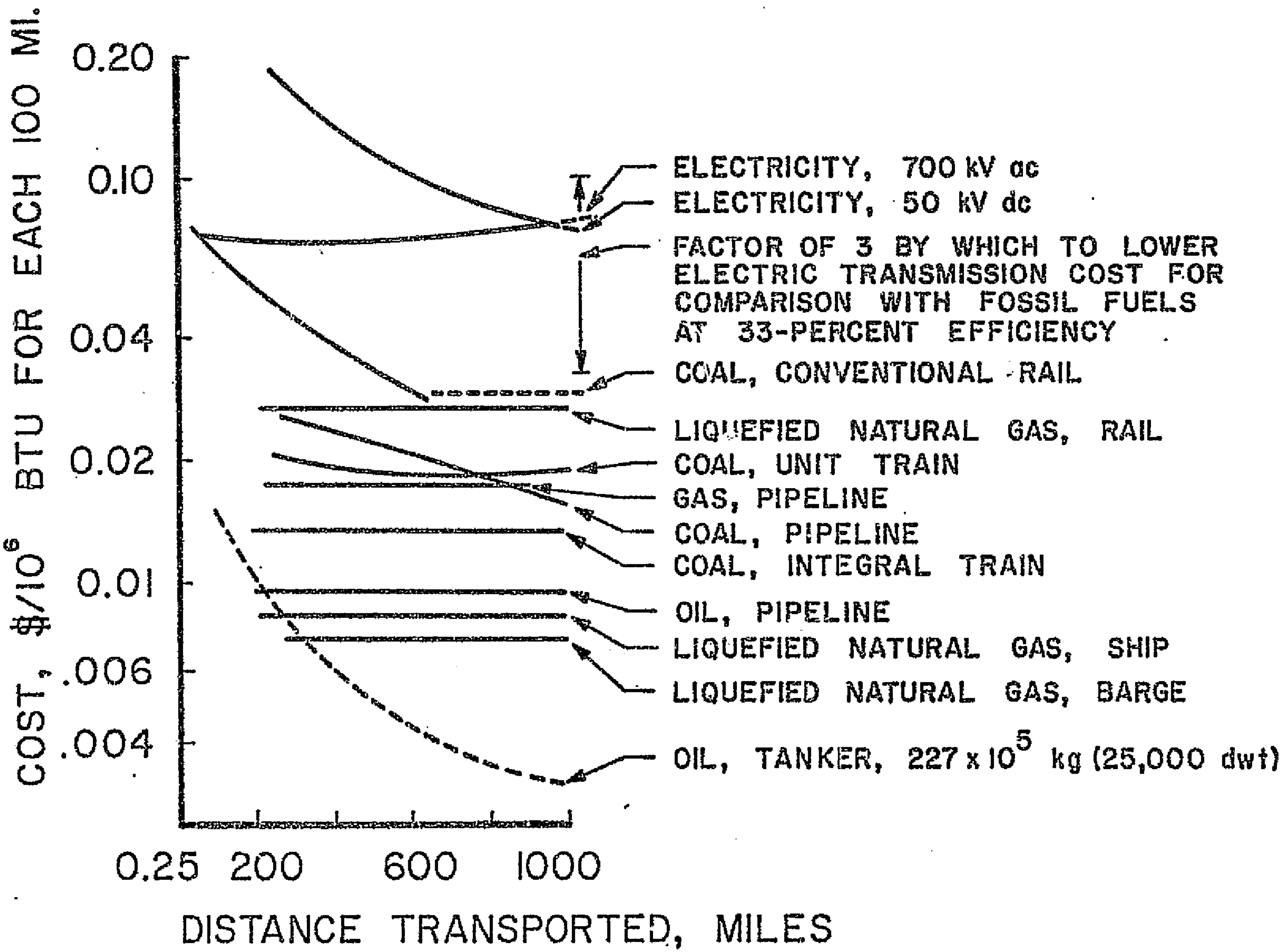

Figure III F.4

Relative Transport Costs for Energy [15]

G. SUMMARY AND CONCLUSIONS

Hydrogen can apparently be pipelined over long distances at costs only slightly higher than for natural gas, and more cheaply than for either overhead or underground electrical systems. Synthetic gases from coal can be pipelined somewhat more cheaply than hydrogen.

Transportation methods for hydrogen other than pipelining cost considerably more than pipelining. Liquefaction costs cannot be balanced by reduced transport costs for liquid hydrogen.

No technical problems are foreseen in pipelining hydrogen, but some research is necessary to make this point absolute.

Closed loop energy pipes use existing technology, and an overall system can provide a given amount of thermal energy more cheaply than hydrogen <u>if</u> the hydrogen is produced by electrolysis. If the thermochemical processes for hydrogen production can be made feasible, then energy in the form of hydrogen can be transported and provided more cheaply.

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IV. USE OF HYDROGEN TO MEET RESIDENTIAL NEEDS

A. INTRODUCTION

Technologically, hydrogen is well suited for residential use in any capacity requiring heat. Air conditioning (by means of absorption cycles), heating, production of hot water, and cooking are feasible now. Lighting by hydrogen can be accomplished either directly using improved mantle design or by conversion to electricity through the use of fuel cells. However, the existence of the well-developed electrical distribution system with its advantages of scale in using centralized plants coupled with the convenience of electrical lighting and the necessity of electricity for other uses make hydrogen an unlikely contender for light production except through use as a fuel in central power plants.

Nevertheless, 88 percent of residential energy supply is presently expended on heating and air conditioning, water heating, cooking, and refrigeration. Also, 85 percent of all residential energy needs presently come from fossil fuels [1]. Residential demand has historically grown at 2.7 percent annually [2]. With these figures, and noting that residential and commercial use accounted for 23 percent of all energy consumed in the United States in 1970 [3], it is obvious that substitution of hydrogen for residential fossil fuel use alone would have a substantial impact. One projection [4] of energy demand for residential use based on the assumptions of widespread conservation practices and of continuation of traditional trends (saturation) is shown in Figure IVA.1.

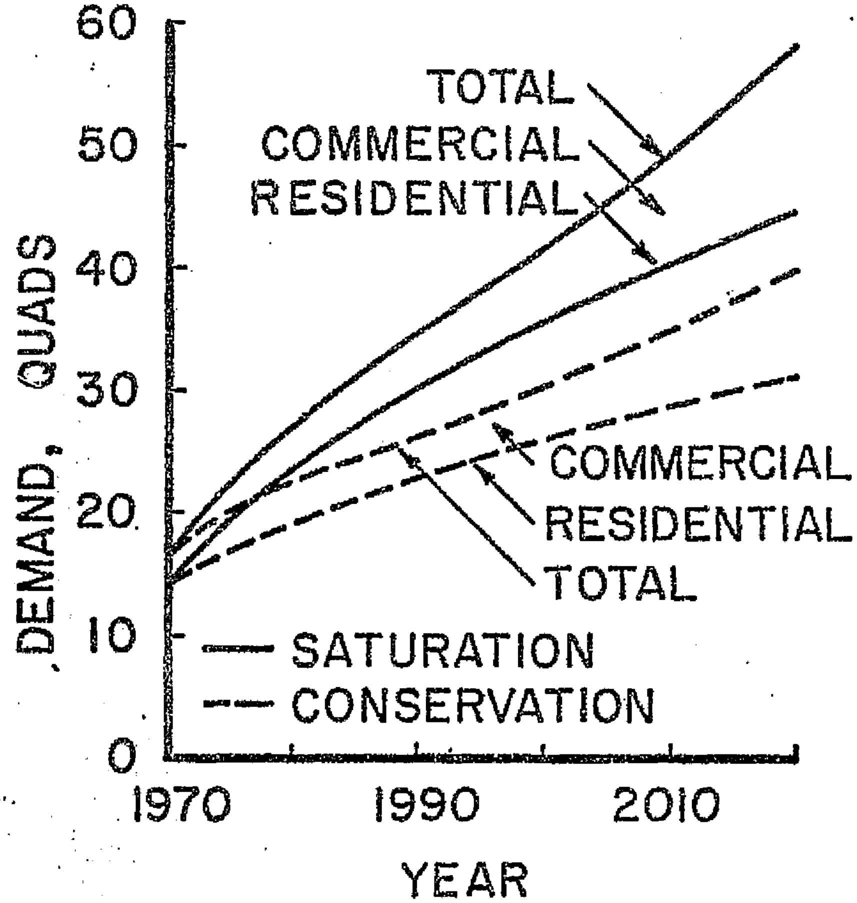

Figure IV A.1
Projected Residential and
Commercial Energy Demand [4]

B. TECHNICAL STATE

1. Catalytic Burners

Sharer and Pangborn [5] discuss the use of catalytic burners for hydrogen, and note that overall system thermal efficiency (production-distribution-usage) is competitive with direct electrical overall system efficiency (about 26 percent). This comparison is based on nuclear/electric versus nuclear/electric/electrolysis/combustion systems. Catalytic combustion, because of its inherent ventless, low-pollutant combustion design gives from 84 to 100% efficient conversion of theoretical hydrogen combustion energy as useful heat in comparison with 60-65% combustion efficiency for natural gas and less for other fossil fuels.

Sharer and Pangborn [5] also note that experimental results on catalytic combustion show that noxious pollutant levels are below those presently required for domestic gas ranges, and the expected NO_x levels are below those required by EPA. They list the following advantages and disadvantages for hydrogen catalytic devices in residential use:

Advantages:

1) Hydrogen-fueled catalytic appliances produce minimal quantities of pollutants.

2) Since noxious pollutants are not produced, appliances can be ventless or chimney-less, which will reduce building construction cost.

3) Humidification of homes can be performed concurrently with heating.

4) The efficiency of a catalytic combustion appliance is higher than that of current conventional natural-gas fueled appliances, and for space heating it can be as high as that of an electrical heating appliance.

5) The efficiency of an overall hydrogen energy system employing catalytic combustion will be higher than the efficiency of futuristic electrical energy systems.

6) Catalytic appliances can be operated at temperatures that decrease the fire hazard within a home.

7) Catalytic appliances can be self-igniting, to eliminate standing pilots or electric ignition systems.

Disadvantages:

1) Hydrogen is not currently available as a fuel, and its availability in the future will depend greatly on the progress of "The Hydrogen Economy."

2) Catalyst life may be limited. Life tests and reliability determinations for catalytic hydrogen appliances have not been performed.

3) Since the hydrogen must be odorized and illuminants added for safety, the compound used must not poison the catalysts.

4) The extreme combustibility of hydrogen causes a hazard that must be tamed. Accidental flame initiation and flashback on catalytic burners must be guarded against with special control systems.

5) Excessive humidification of homes may be a problem that could necessitate dehumidification systems. (An offsetting advantage is the pure water obtained.)

Table IVB1.1, from reference 5, details the projected efficiences of electrical vs. hydrogen energy systems.

Despite the relative optimism of Sharer and Pangborn [5], there remain serious questions about catalytic burning -- chiefly, the availability of the catalyst materials themselves for exceedingly large scale use. Present catalysts in use are the noble metals, including tungsten, rhodium, palladium, and platinum. Laramore, et al[6] report on possible alternative catalysts.

TABLE IVB1.1

Efficiencies for Various Energy Systems [5]

System	Nuclear Heat to Fuel	Transmission Storage, Distribution	End Use	System Efficiency
		%		
H_2, today (electrolysis)	29 x 77*	95	65	14
Electricity, today	29	95	95	26
H_2, future (electrolysis)	45 x 95*	95	70(flame) 84(catalytic)	30 36
Electricity, future	45	90+	95	38
H_2, future (thermo-chemical)	55	95	70(flame) 84(catalytic)	37 44

* With current technology, proved nuclear reactor-steam turbine systems can generate electricity at 29% efficiency. Electrolysis is 77% efficient. Futuristic values of 45% electrical generation and 95% electrolytic efficiency are expected.

+ Due to the remote locations of nuclear power plants, line losses will be greater, causing a decrease in efficiency.

2. Flame Burning

Production of heat by open burning of hydrogen requires essentially a completely new system; that is, modification of the existing natural gas system in a residence is not economically reasonable. New meters, burners, pressure regulators, plus inspection, testing, and perhaps upgrading of the piping supply system are required, and replacement of components of an existing natural gas system may be more expensive and will be less efficient than replacing the entire system in the home [7]. Most other synthetic gaseous fuels such as SNG or coal gas have burning properties close enough to those of natural gas that little conversion of hardware is necessary except for burner adjustment.

Flame burning, given compatible burners, is inherently clean and potentially no more hazardous than for natural gas. Unvented burners can be used, with the only difficulty being the production of water vapor and the possibility that dehumidification may be necessary. Efficiencies for such burners can approach 100 percent.

3. Fuel Cells

Fuel cells have great advantages for production of electricity from hydrogen in the residential sector. They are clean, quiet, possess no moving parts, and have high efficiencies. However, they have two serious disadvantages. One, at present they require electrodes using critical materials, such as platinum, palladium, rhodium or nickel. Two, they produce direct current and thus require an inverter to produce alternating current. Given that the probable appliance mix in the future will be compatible with the present electrical distribution system, an inverter will probably be necessary. These two factors make it unlikely that fuel cells will be used in the residential area unless electrode technology produces breakthroughs in materials and cost, and low-cost inverters of high capacity and reliability are developed [8].

C. COMPARISON WITH OTHER SYNTHETIC FUELS

Other possible candidates for residential fuel use have been discussed in the literature. Here, we concentrate on those derived from fossil fuels, chiefly coal. These include methanol, SNG, and coal gas. Also, ethanol from fermentation will be examined, as will methane from solid wastes. The latter two will be examined first.

1. Ethanol from Fermentation

This process is, of course, well-developed in the booze industry. However, even though ethanol is a convenient, easily handled fuel, at least three serious problems make this method of fuel production unlikely as a competitor for hydrogen in the future:

1) The method requires extremely large amounts of land to produce the required energy. For example, Michel [7] notes that to replace only the tetraethyl lead in gasoline, which would require ethanol in volumes of 10 percent of the present yearly gasoline consumption, it would take 8.8×10^9 gallons/year of alcohol. This would require 3.3×10^9 bushels of grain, requiring about 40 million acres of land.

2) Given the world food situation, it is doubtful that land usage of this magnitude is acceptable.

3) It is not clear that the usage of fuel for fertilizer production, farming, and grain drying makes the whole process a net energy producer.

2. Methane from Solid Wastes

Again, limitation of resources make this an unlikely candidate for large-scale fuel production. About 2 X 10^9 tons of manure is generated yearly in the United States, 80 percent of which is of agricultural origin. However, about 50% by weight of this waste is water [9]. Of this waste, then, only about 136 X 10^6 tons of dry, ash-free waste was easily collectable for use. This would produce, according to Michel [7] about 1.4 X 10^9 SCF of methane, or about 6 percent of the 1971 consumption of natural gas. Up to 40 percent of present natural gas demand could be met if all usable waste were collected; again however, the energy cost for collection and drying of this diffuse resource must be considered.

3. Methanol from Coal

Methanol is manufactured from coal by coal gasification to produce synthesis gas (CO and H_2), which is then purified and used in a conventional methanol synthesis reactor. Michel [7] shows that the cost of coal is the dominant cost factor in this process. Reed and Lerner [9] emphasize that any hydrocarbon feedstock can be used in this process, including fossil fuels, solid waste and agricultural products. However, they also point out that production of synthesis gas from each of these feedstocks, while simple in concept, is often difficult in practice. If low purity methanol is allowable, so that other alcohols are present in the product, then plant yield can be improved by up to 40 percent. This "Methyl-Fuel" [10-12] has higher energy content than pure methanol, and has better solubility at low temperatures as a gasoline supplement.

Synthesis gas from coal is not rich enough in hydrogen for direct production of methanol. The water-gas shift reaction can be used to adjust this ratio, but produces CO_2 which then must be separated and vented to the atmosphere. This represents a waste of carbon and a reduction in process efficiency. If hydrogen were available as a direct supplement to the synthesis gas, then direct production of methanol could be done. This is one possible large-scale use for hydrogen in a future mixed-source energy economy.

Because of their liquid form, methanol and "Methyl-Fuel" have advantages over hydrogen in pipelining costs, and in suitability for use in transportation vehicles. They suffer from the common difficulty of all carbon-based fuels -- they depend on either inadequate waste products for feedstocks, or on fossil fuels which are, except for coal,

in short supply. Coal, however, will have strong competitors for its use, and can be expected to increase drastically in price for this reason. In the residential sector, conversion to a liquid fuel is probably much more expensive than conversion to hydrogen. All new appliances, metering and regulating equipment would need to be developed <u>in addition to</u> an entirely new distribution system.

4. SNG and Coal Gas

In the short to medium run, these gaseous fuels are sure to be the chief competitors to hydrogen. They are produced relatively cheaply using conventional technology needing only reasonably straightforward development. They can use the existing natural gas distribution system with no modification, and the existing gas appliance designs probably need at most minor burner adjustments.

In the short to medium run, hydrogen probably cannot compete with the natural gas/SNG/coal gas production-distribution-use system simply because of the huge capital plant already in existance or available for these fuels. In the long term, however, the feedstocks for these gases will be exhausted as shown in Section II-A. At that time, no viable competitor for hydrogen as a gaseous residential fuel will exist.

5. Electricity

As with hydrogen, electricity has certain intrinsic advantages that make it virtually irreplaceable as an energy form for residential use. Barring local electrical production by fuel cells or solar cells, electricity from above- or underground transmission and based on a multitude of primary energy sources (fossil/nuclear/hydroelectric/geothermal/solar, etc.) will be necessary in the foreseeable future [13]. Operating stereos, microwave ovens, T.V.'s, and lighting equipment with hydrogen, although possible through local conversion, is probably not economically reasonable.

As with hydrogen, a primary energy source must be used to produce electricity. With the single exception of hydroelectric production, all such sources are used to convert heat to electricity with efficiencies of 30 to perhaps 45 percent. For distribution, line losses become excessive for distances greater than a few hundred miles. Hydrogen can be produced and distributed with comparable or better efficiencies [5]. For end uses involving heat, then, hydrogen has advantages over electricity in cost and convenience. It is reasonable that in the future, especially the far term, both energy forms will be used in the residential sector, each performing the functions for which they are best suited. This is the case today, where electricity and natural gas coexist in many homes.

For an opposing view, see the article by Ross [14].

D. SUMMARY

In the short and mid-term, residential requirements for energy will continue to be met by utility-provided electricity coupled with utility-provided natural gas transitioning to SNG and coal gas. In the long-term, as fossil fuels are exhausted and/or their price increases drastically, reliance on hydrogen from non-fossil fuels will increase. Electricity will remain a major energy supplier even in the long-term.

The possible conversion to hydrogen for residential use is shown in Figure IVD.1 taken from reference 15.

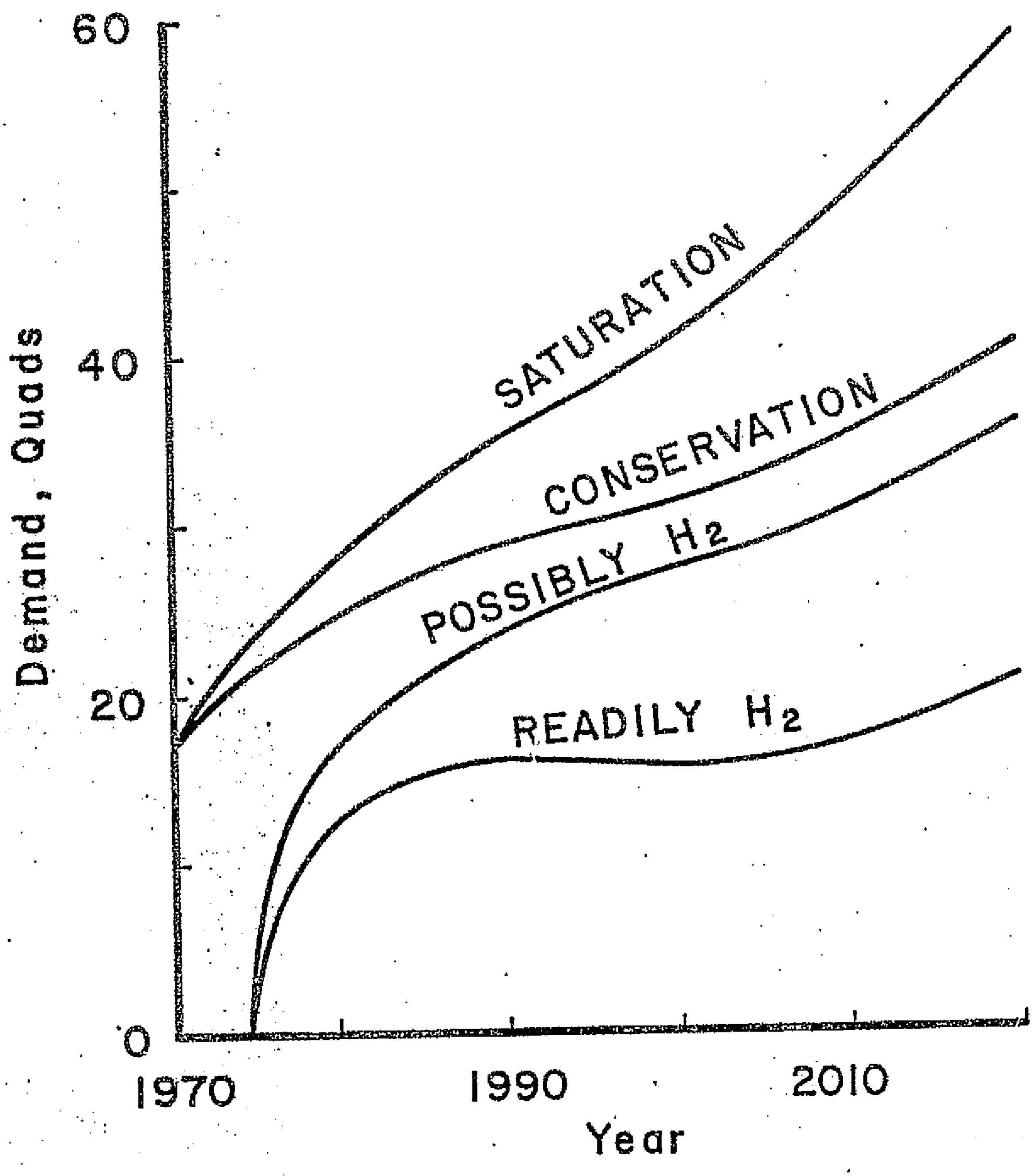

Figure IV D.1

Possible Conversion to Hydrogen of Residential Energy Use [15]

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